Impact of Independent Power Producers and Distributed Power Generation on Environmental Emission and Utility Planning in Northern Regional Electricity Board Network

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APRIL, 2002

IMPACT OF INDEPENDENT POWER PRODUCERS AND DISTRIBUTED POWER GENERATION ON ENVIRONMENTAL EMISSION AND UTILITY PLANNING IN NORTHERN REGIONAL ELECTRICITY BOARD NETWORK

A Thesis Submitted
in Partial Fulfillment of the Requirements
for the Degree of

MASTER OF TECHNOLOGY

by

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to the

DEPARTMENT OF ELECTRICAL ENGINEERING
INDIAN INSTITUTE OF TECHNIOLOGY, KANPUR

APRIL, 2002

CERTIFICATE

This is to certify that the work contained in this thesis entitled "**Impact of Independent Power Producers and Distributed Power Generation on Environmental Emission and Utility Planning in Northern Regional Electricity Board Network**", has been carried out by Bikash Kumar Barnwal (Y010407) under my supervision and that this work has not been submitted elsewhere for a degree.

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Acknowledgement

It is my proud privilege to express my deep sense of gratitude and indebtedness towards my thesis supervisor Dr. S. C. Srivastava for his excellent supervision, skilled guidance, stimulating discussions, inspiration and constant encouragement, which were the vital factors in successful completion of the present work. I would like to treasure his love and affection for me.

I am extremely thankful to Dr. B. C. Pal, Dr. S. S. Prabhu, Dr. Sachchidanand and other faculty members of IIT Kanpur for their sincere attitude and guidance.

This thesis is part of the project number AIT/EE/19990071 and 19990098, jointly carried out by IIT Kanpur and CEA, New Delhi and sponsored by Swedish Industrial Development Cooperation Agency (Sida) and Asian Institute Technology, Thailand. Financial support under this project for carrying out the present work is duly acknowledged.

I am thankful to Mr. Anurag Kumar Srivastava for his support in carrying out this work and invaluable suggestions. I would also like to cherish the nice company of my friends Ullash, Sanjay, Ashwani, Barjeev, Balaji, Kishore, Manoj, Meena, Saleem, Krishna, Sonkar and all the friends at the Institute for creating a pleasant atmosphere during my stay at I.I.T Kanpur.

Last but not the least, I would like to thank the Almighty and my family members who enabled me to reach at this stage, where I could undertake the work of this magnitude.

Bikash Kumar Barnwal

CONTENTS

List of Figures

List of Tables

Abstract

1.	**Introduction**	...	1
1.1	General Introduction	...	1
	1.1.1 Generation expansion planning	...	1
	1.1.2 Generation expansion planning packages	...	2
1.2	Environmental Impacts of Power Sector	...	3
	1.2.1 Greenhouse gases and global warming	...	3
	1.2.2 Other emissions from power sector and their side effects	...	4
1.3	State-of-the-art	...	4
	1.3.1 Independent power producers	...	5
	1.3.2 Main features on the policy of the power sector development in India	...	6
	1.3.3 Distributed power generation	...	7
1.4	Motivation Behind The Study	...	9
1.6	Thesis Organization	...	11
2.	**Impact of Independent Power Producers on Generation Planning**	...	12
2.1	Introduction	...	12
2.2	Methodology	...	13

2.3.1 Overview of the NREB system, India ... 16
2.3.2 Electricity demand, energy requirement and load factor data ... 17
2.3.3 Assumptions used in the analyses ... 18
2.3.4 DSM options ... 19
2.3.5 Description of cases ... 20
2.4 Results and Discussions ... 21
2.4.1 Utility planning implications ... 21
2.4.2 Cost and pricing implications ... 33
2.4.3 Environmental implications ... 37
2.5 Conclusions ... 41

3. Impact of Distributed Power Generation on Generation Planning ... 44

3.1 Introduction ... 44
3.2 Methodology ... 45
3.3 Input Data and Assumptions ... 47
3.4 Results and Discussions ... 48
3.4.1 Utility planning implications ... 48
3.4.2 Cost and pricing implications ... 55
3.4.3 Environmental implications ... 56
3.4.4 Sensitivity analyses ... 57
3.4.5 Analysis considering candidate DPG plants individually ... 61
3.5 Conclusions ... 66

4. Conclusions ... 68

References

Appendices

List of Figures

1.1	Distribution of IPP investment among selected developing countries, 1997	...	6
1.2	Conventional utility response to meet the new demand	...	8
1.3	DPG alternative to meet the new demand	...	8
2.1	Flowchart to calculate effects of IPP plant on environmental emission	...	15
2.2	Expansion costs for IPP	...	34
2.3	Total emissions	...	38
3.1	Flowchart to identify feasible DPG plants	...	46
3.2	Flowchart to calculate effects of DPG plant on environmental emission	...	47
3.3	Expansion costs for DPG	...	55

List of Tables

Table no. Title	Page No.
2.1: Present installed capacity in NREB	16
2.2: Electricity demand, Energy Requirement and Load Factor data	17
2.3: DSM options	19
2.4: Capacity mix by plant types	22
2.5. Generation mix by plant types	23
2.6: Technology options (Number of units) selected	24
2.7: Capacity utilization of the system	25
2.8: Reliability of the system	26
2.9: Effect of change in MOC of IPPs on capacity mix	27
2.10: Effect of change in MOC on av. Capacity utilization and av. Unserved energy	27
2.11: Effect of change in unit size of IPPs on capacity mix	28
2.12: Effect of change in unit size on av. unserved energy and av. capacity utilization	29
2.13: Effect of change in plant availability factor on capacity mix	29
2.14: Effect of change in availability factor on av. unserved energy and av. capacity utilization	30
2.15: Effect of change in amount of electricity purchase from IPPs on capacity mix	31
2.16: Effect of change in amount of electricity purchase on av. unserved energy and av. Capacity utilization	31
2.17: Effect of change in duration of contract on capacity mix for TRP cases	32
2.18: Effect of change in duration of contract on av. unserved energy and av. capacity utilization	33
2.19: Expansion costs during planning horizon	33
2.20: Electricity price for expansion planning cases	34
2.21: Effect of change in minimum operating cost of IPPs on expansion costs	35

2.22: Effect of change in unit size of IPPs on expansion costs 35
2.23: Effect of change in plant availability factor on expansion costs 36
2.24: Effect of change in amount of electricity purchase from IPPs on expansion costs 36
2.25: Effect of change in duration contract on expansion costs 37
2.26: Total environmental emissions 37
2.27: Effect of change in MOC of IPPs on environmental emission 38
2.28: Effect of change in unit size of IPPs on environmental emission 39
2.29: Effect of change in plant availability factor of IPPs on environmental emission 39
2.30: Effect of change in amount of electricity purchase from IPPs on environmental emission 40
2.31: Effect of change in duration of contract on environmental emission 41
3.1: Estimated potential of renewable in India 48
3.2: Capacity mix (%) by plant types for TRP cases 49
3.3: Capacity mix (%) by plant types for IRP cases 49
3.4: Generation mix (%) by plant types for TRP cases 50
3.5: Generation mix (%) by plant types for IRP cases 51
3.6: Technology options (Number of units) selected 52
3.7: Capacity utilization of the system 53
3.8: Reliability of the system 54
3.9: Expansion costs during planning horizon 55
3.10: Electricity price for expansion planning cases 56
3.11: Total environmental emissions 56
3.12: Effect of change in unit size of DPG on capacity mix for the TRP cases 57
3.13: Effect of change in unit size of DPG on capacity mix for the IRP cases 57
3.14: Effect of change in unit size of DPG on av. unserved energy and av. capacity utilization of the system 58
3.15: Effect of change in unit size of DPG on expansion costs 59
3.16: Effect of change in unit size of DPG on environmental emission 59
3.17: Capacity mix (%) for TRP cases 61

3.18: Capacity mix (%) for IRP cases 62
3.19: Generation mix (%) for TRP cases 63
3.20: Generation mix (%) for IRP cases 64
3.21 Average capacity utilization and average unserved energy 64
3.22 Effect of different DPGs on Expansion Costs 65
3.23 Environmental Implications 66

ABSTRACT

In most of the Asian countries, including India, the electricity generation is largely based on fossil fuels. These power plants produce pollutants such as CO_2, SO_2, NO_X and particulate matters cause global and local environmental problems. The contribution of power plants in Greenhouse gases emission has been found to be significant, causing global warming effect. The power sector in most of the countries, including India, is in the process of restructuring which promotes the introduction of independent power producers (IPPs) and distributed power generations (DPGs). However, not much literature is available to quantify the impact of IPPs and DPGs on the power sector planning, specifically their impact on environmental emissions.

In this work, the utility planning, cost & planning and environmental implications of IPPs and DPGs have been studied. The study has been carried out for the Northern Regional Electricity Board (NREB) network of India utilizing 16th Electric Power Survey data published by the Central Electricity Authority. Sensitivity analyses have also been carried out with respect to few important parameters associated with IPPs and DPGs to observe the trend in which the generation expansion planning shifts from its base case. In addition, the planning analyses have also been carried out for each of the DPG plants individually to identify their cost-effectiveness and environmental implications.

The study results reveal that the introduction of both IPP and DPG plants results in environmental emission mitigation and reduction in the total expansion cost. DPG based on wind power plants are found to be the most cost-effective and those based on micro hydro have the highest environmental emission mitigation potential

can be either due to system faults when it is in operation (for e.g. sudden increase in load, generator and line outage etc.) or of social nature like environmental constraints put on the system.

In the literature, there are two approaches for Generation expansion planning: stochastic and deterministic approach [2]. The stochastic approach takes uncertain factors into account in an explicit manner. The deterministic approach evaluates system performance under different scenario. It is basically a process of optimizing the total cost of the planning process with all the constraints taken into account. The constraints could be environmental, fuel, financial, load demand etc. In this thesis, the deterministic approach has been considered and the least cost generation expansion planning approach has been utilized.

The least cost planning is done in two ways: traditional planning and integrated planning. Traditional planning is done by first of all forecasting the load demands beforehand, formulating a problem including all the existing and candidate generating units, all types of constraints, the chronological load curve and the forecasted demand and then optimizing this problem to find a least cost solution. Integrated planning is performed in the same way as the traditional planning but also including the demand-side management options in the problem formulation.

1.1.2 Generation expansion planning packages

In India, under the Electricity Supply Act, 1948, Central Electricity Authority (CEA) is responsible for power planning at the national level. CEA advises the Department of Power (Ministry of Energy) on the national power policy, national power planning and regulatory matters. At present in India, CEA has been using two computer software models for power generation expansion planning, namely:

1. Electric Generation Expansion Analysis System (EGEAS)
2. Integrated System Planning Model (ISPLAN)

The EGEAS model, being a probabilistic model, provides for long range generation expansion planning as it yields very useful quantitative measures of reliability of power supply in the future years and gives the total cost of operating the existing and committed system and installing and operating the new systems. The transportation of fuel and transmission of power are not considered in the EGEAS model and considered in ISPLAN.

The siting of new generating stations, that use transportable fuel, is done using ISPLAN. Under ISPLAN the broad features of the transmission system are also obtained. The EGEAS model is probabilistic model, whereas ISPLAN is deterministic model. CEA utilizes the power reliability indices as Loss of Load Probability (LOLP) of 2% and Energy not Served (ENS) not to exceed 0.15% [3]. Other than these two software packages, several other packages is also available for least cost generation expansion planning. They are WASP. DECADES, PROSCREEN, EFOM, MARKAL. In this thesis, an Integrated Resource Planning and Analysis (IRPA) [4] model is used for least cost generation expansion planning. The model finds an optimal (least cost) expansion plan with supply- and demand-side options included.

1.2 ENVIRONMENTAL IMPACTS OF POWER SECTOR

1.2.1 Greenhouse gases and global warming

Power generation based on extensive use of fossil fuels, viz. coal, natural gas and petroleum, major deforestation and growth in the agricultural production have increased the level of greenhouse gases (GHGs). The main greenhouse gases are carbon dioxide, methane, chloro fluro carbon, ozone, nitrous oxide and H_2O (as stratospheric water vapor) out of which CO_2 constitutes the largest percentage. The power sector has been reported to be a major contributor to CO_2 emissions. Eight countries of the world viz. Canada, USA, France, Germany, Italy, UK, Japan and Russia are responsible for the major production of carbon dioxide. Most of the Asian countries are rich in fossil fuels and as these countries are developing rapidly, the power generation based on fossil fuels is increasing at a faster rate contributing towards the increase in green house gases.

Greenhouse gases accumulate in the atmosphere, block infrared radiation to the outer space and reflect the heat radiated from earth back to the earth itself. This process is indeed necessary for life on earth as it maintains the earth's temperature at desired value. However, the excessive increase in GHG level has led to the global warming and resulting into change the earth's climate. The global average surface temperature is projected to increase by 1.4 ^{0}C to 5.8 ^{0}C from 1990 to 2100 [5]. Global warming will cause frequent natural disasters such as rise of seawater level, submergence of low lying area, storms, floods, desertification etc. Sea levels are projected to rise by 90 mm to 180 mm from 1990 to 2100 [5].

1.2.2 Other emissions from power sector and their side effects

Fossil fuels fired power plants also emit local pollutants other than carbon dioxide which are very hazardous to the human health. These are sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM10) and lead (in a very small amount) [6]. The major effects of these emissions are acid rain and increasing concentration of ozone in atmosphere.

Acid rain is caused by contamination of rain, fog or mist with sulfur dioxide and nitrogen oxides present in the air. These gradually react with water vapor in the clouds and become acids and reach the earth through rainwater. Undissolved acids may also fall on Earth by themselves or in combination with dust particles. These can acidify the surface waters and soil. This acidification of the water harms the aquatic life in lakes and rivers. In general, acid deposition, among other stressors, threatens the long-term structure, function, and productivity of many sensitive ecosystems.

Nitrogen oxides, emitted from power plants (along with VOCs) react in atmosphere in the presence of sunlight to form ozone. Strong concentrations of ozone can result in respiratory problems, irritation of eyes and mucous membranes. High levels of ozone can be harmful to vegetation also. Fossil-fuel power plants also produce a large amount of waste heat. Generally two-third of the heat value of the fuel pollutes the atmosphere thermally.

1.3 STATE-OF-THE-ART

The emission of Green House Gases (GHG) and global warming associated with it has made environmental issues to be much discussed in the recent literature. The power sector has been reported to be one of the main contributors of carbon dioxide emissions in many countries in Asia. As of 1999, the share of power sector in total carbon dioxide emission was estimated to be 45.6% in India, 41.9% in China and 33.6% in Thailand [1].

Electricity generation in Asia as a whole is expected to increase at a higher rate than the global average. The share of thermal power generation is also likely to increase given the expected growth of the electricity generation in this region. The share of thermal electricity generation are expected to increase from 78% in 2000 to 81% in 2010 in case of India and from 94% in 2000 to 96% in 2010 in the case of Thailand [7,8]. As on 31st March 2000, out of total capacity of 98,187 MW produced in India, 70,536 MW is produced by thermal

power plants [9]. Coal-based power plants share the major part of the power produced in India as it has large reserves of coal.

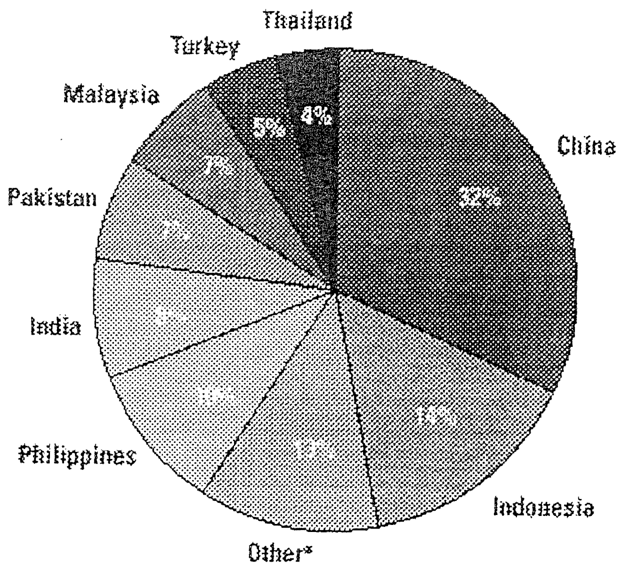
The coal-fired plants are a major source of greenhouse gases (GHGs) emission. According to a World Bank report, CO_2 emission in India by the year 2015 will be 775 million metric tons per year, as compared with 1000 million metric tons per year now produced by the entire European union. It also expects that SO_2 and NO_X production will be at three times the current levels [10]. From a global perspective, India will account for 18% of the increase in carbon emissions produced from energy use in developing countries between 1985 and 2025 [11]. Hence, it has become mandatory to explore all the options while bringing the emission of pollutants within a target set.

Recently, power sector restructuring has received substantial impetus in the Asian developing countries. One of the major components of power system restructuring is the participation of Independent Power Producers (IPPs) and Distributed Power Generations (DPGs). Though the participation of IPPs and DPGs is increasingly considered desirable by the developing countries in the long run, no proper study has been carried out regarding their environmental implications especially in the Asian countries. With the introduction of IPPs and DPGs, a utility would avoid generation and hence associated environmental emissions.

1.3.1 Independent power producers

Figure 1.1 gives the distribution of IPP among selected developing countries. Asia enjoys one of the biggest shares of IPP market with 103 contracts worth US$54 billion [12]. Bhattacharya (1995) argues that it is not clear whether privatization would lead to environmental benefits in terms of reduction in emission of air pollutants (i.e. CO_2, SO_2 and NO_x) [13]. Littlechild (1992) noted that the impact of competition in the power sector in the UK has been towards the increased orientations to efficiency in electricity productions [14]. Hamrin and Rader (1992) argue that the IPPs development could be affected by the environmental considerations [15]. If renewable energy projects, efficient generation technologies and energy efficiency programs are to be fairly evaluated in market, their environmental attributes must not only be recognized in the selection process, but the contract price actually paid must reflect the value of their beneficial environmental qualities. A study has been done by UNESCAP in selected countries of Asia on consequences of

private power generation on environmental quality. This study, however, was focused on the review of the environmental regulations of the selected countries [16]. As shown by Hagen and Vincent (1989) and Teplitz-Sembitzky (1992), that with diverse technology, power purchase from IPPs would affect the utility merit order dispatch [17,18]. This change in merit order dispatch is either due to the change in the shape of the load duration curve or due to the change in the relative input prices of various technologies. Therefore, as a result, generation mix would change and, in turn, it changes the environmental emissions.



Note: Data are as of end-December and cover only IPP projects of more than 100 megawatts.
a. Argentina (3 percent), Chile (2 percent), Colombia (2 percent), Morocco (2 percent), Czech Republic (1 percent), Lao PDR (1 percent), Mexico (1 percent), and Peru (1 percent).
Source: World Bank, Energy, Mining, and Telecommunications Department, Knowledge Management database.

Fig. 1.1: Distribution of IPP investment among selected developing countries, 1997

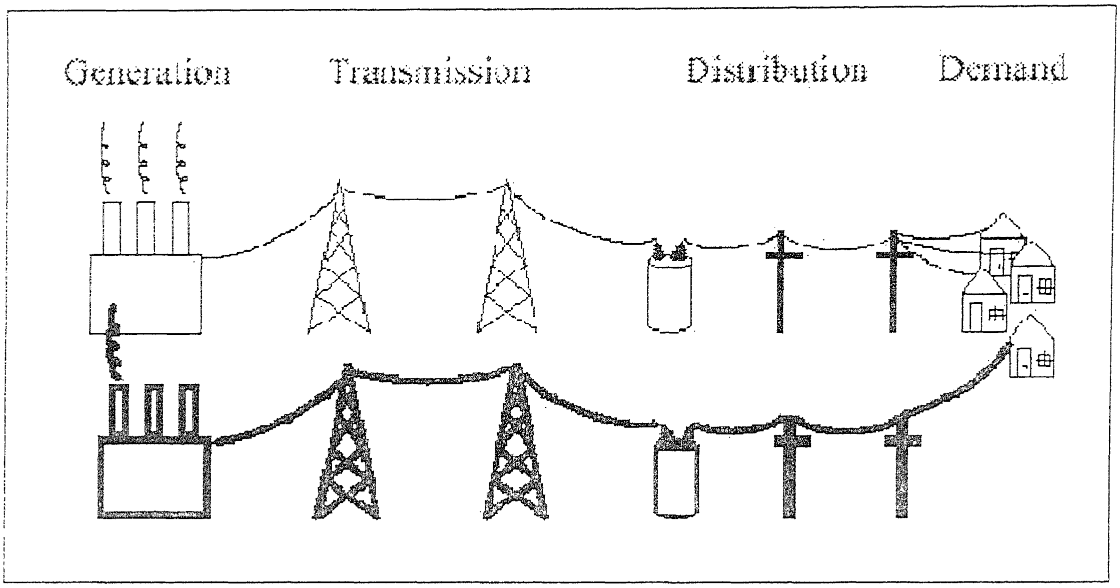
1.3.2 Main features of the policy on power sector development in India

Private participation in the power sector is not a novel concept in the Indian context. The private sector has been a participant in India's electricity sector for over a hundred years. These private power companies operate their own power generation and distribution systems and have a total capacity of around 3000 MW as on 1995. They distribute power to around 10 million consumers [19].

Economic liberalization and to mobilize additional resources for the sector to bridge the gap in demand and supply, the government has encouraged greater investment by private enterprise in the electricity sector. The government formulated a policy in 1991 to encourage greater investment by the private sector in the power sector. The new policy permits 100% foreign owned companies to set up power projects and repatriate profits without any export obligations. The Investment Promotion Cell (IPC) was also set up in the same year under the Ministry of Power as a nodal agency to provide information and assistance to prospective entrepreneurs in the electricity sector. IPC provides information on the policy regarding private sector participation in the power sector. It facilitates speedy clearances by being the single reference agency to resolve the various issues related to private participation in the power sector. An attractive two-part tariff structure was provided through a notification in March, 1992 which allowed recovery of full fixed charges with up to 16% return on equity at specified plant load/ availability factor. This was further modified in January 1994, August 1994, January 1995 and November 1995 making the policy more attractive and flexible. The policy also permits private participation in Renovation and modernization of existing power stations and setting up captive/ co-generation plants to maximize productivity and efficiency. These all policy marks a fresh initiative to involve the private sector in the Indian power generation in much bigger way.

1.3.3 Distributed power generation

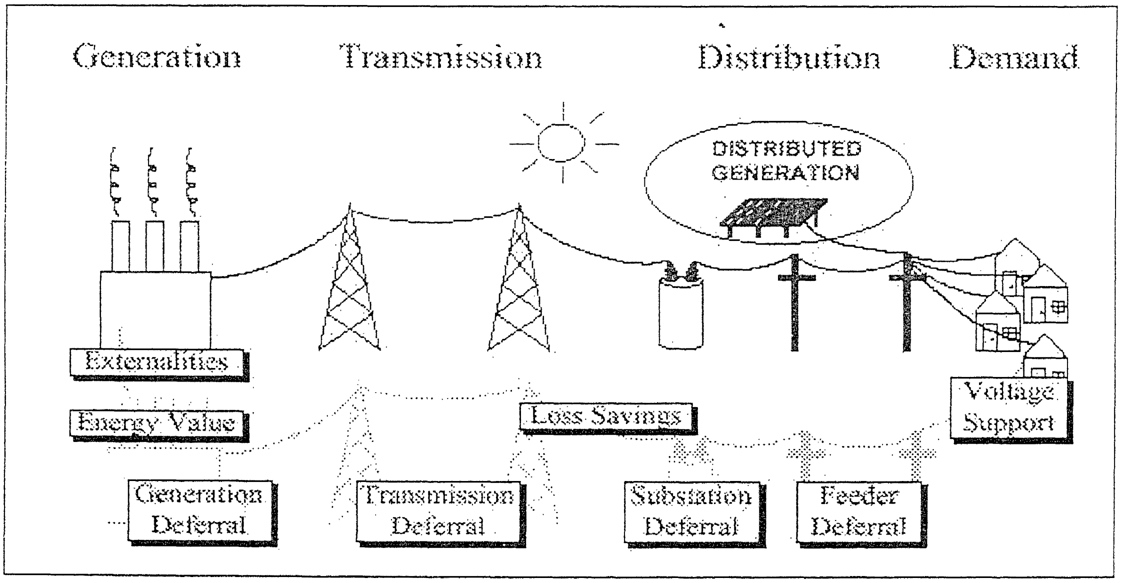
Generally, electric utilities satisfy customer demand by generating electricity centrally and distributing it through an extensive transmission and distribution network. As demand increases, the utility generates more power. Once demand increases beyond a certain limit, the capacity of generation, transmission and distribution systems can be stressed. Utility responds to these constraints by building new facilities that are shown in figure 1.2. An alternative approach can be to invest in distributed generation by satisfying demand locally. Distributed generation facilities are strategically sited to deliver electricity where it is needed. This can relieve capacity constraint on the generation, transmission and distribution system and obviate the need to build new facilities that is shown in figure 1.3.



Source: http://www.clean-power.com/research.htm

Figure 1.2: Conventional utility response to meet the new demand

Distributed power generation can be defined as supply side resources that can be deployed throughout an electric distribution system (as distinguished from the transmission system) to meet the energy needs of the customers served by that system [20]. Ackerman et al defined it as an electric power source connected directly to the distribution network or on the customer side of the meter [21].



Source: http://www.clean-power.com/research.htm

Figure 1.3: DPG alternative to meet the new demand

Petrie et al noted that the primary source of power for DPG in developing countries is reciprocating engines fueled by diesel or natural gas and renewable energy sources [22]. In India, distributed power generations are mainly based on solar, wind and micro-hydro.

David Moskowitz concluded that location of the distributed resources is critical and how utilities are regulated is important to the use of distributed resources [20]. He has also discussed about environmental benefits, as use of DPG promotes renewable source and avoids T&D losses. This paper also presented a detailed discussion on profits through distributed resources.

Jami Hossain and Chandra Shekhar Sinha have discussed carbon offsetting with renewable potential in the power sector in India and they have found it as total of 15,425 MW including biomass, wind, small hydro, solar system etc [23]. They have also suggested some potential sites for wind power plants in India.

Thomas E. Haff et al described DPG as one of the solution to cut carbon emissions [24]. They found DPG also economical if implemented over a time frame of 30 to 50 years. because in this time period, system may need many T&D upgrade. Authors have given consideration to both the technical and economical aspects of DPG.

1.4 MOTIVATION BEHIND THE STUDY

Emission of greenhouse gases and other pollutants from the power sector and its firmly established link with global warming and environmental pollution has made this issue to be much discussed in the recent past. It has become a major concern all over the world to put a cap on the emissions from the power sector. Many of the developed countries have agreed to the Kyoto protocol and started an attempt to curb the greenhouse gas emissions. The United States signed the Framework Convention on Climate Change (FCCC) during the 1992, United Nations Conference on Environment and Development. Emission in developing countries is also increasing rapidly as the power sector is expanding at a much faster rate to meet their economic growth and with having large reserves of fossil fuels. Hence, it has become a moral responsibility for developing countries also to take some fast action for abatement of greenhouse gases. Also there is a lot of pressure from the developed countries on developing countries to curb their greenhouse gas emissions.

In the recent past, power sector in India is getting restructured and reformed to manage its environmental implications. India is moving from a publicly owned, vertically integrated, monopolistic power system to a more deregulated, more liberal, more reliable system where competition is being introduced at all the level by introducing more corporatization and privatization in the market. Private generation companies are being encouraged to participate at the generation level by negotiating some fixed power purchase agreement (PPA) with them. The introduction of large-scale independent power producers (IPPs) will completely change the picture of the power sector in India. At a time when these changes are taking place in the sector, it is better to move ahead with keeping environmental implications in mind and restructuring the power sector on that basis.

India has large reserves of coal and it accounts for almost 70% of the electricity generation in the country. However, the excessive use of coal produces large amount of carbon dioxide due to their high carbon content and incomplete combustion and contributes towards the global warming. The total contribution of India in carbon emissions is estimated to be 45.6% in Asia. So it has become the need of the moment to shift our electricity generation from conventional fuels to renewable energy supplies as much as possible and shake hands with the rest of the world in making it pollution free. Hence a lot of distributed power generations (DPGs) based on renewable sources have come up recently.

Since independent power producers and distributed power generations are going to play a very important role in the near future in the power generation sector, it has become imperative to know their environmental implications in the long-run. This study has been carried out to quantify the environmental as well as planning implications of IPPs and DPGs. The main objectives of this study has been the following:

1. To find out the utility implication, cost implication and environmental implication of IPPs and DPGs including their effect on the reliability of the system.
2. To find out the effect of changing some specific parameters associated with IPPs and DPGs and carry out sensitivity analyses to study their implications on the generation expansion planning.

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1.5 THESIS ORGANIZATION

This thesis has been organized in four chapters.

The present **Chapter 1** gives a brief outline of the generation expansion planning and the packages used to perform such study, discusses environmental impacts of power generation expansion, presents a brief state-of-the-art with regard to IPPs and DPGs and sets the motivation behind this study.

Chapter 2 provides the generation expansion planning results analyses, the cost and environmental implications of IPPs. The study has been carried out for Nortehrn Regional Electricity Board system of India.

Chapter 3 presents the results of the generation expansion planning and provides the cost, utility & environmental implications of DPGs. It also provides the cost-effectiveness and environmental emission mitigating potential of individual types of DPG plant.

Chapter 4 concludes the main findings of the work reported in this thesis and identifies areas of further research.

CHAPTER 2

IMPACT OF INDEPENDENT POWER PRODUCERS ON GENERATION PLANNING

2.1 INTRODUCTION

Independent power producers (IPPs) are playing an increasingly important role in providing new electric power generations capacity in many developing countries. In India, as the gap between demand and supply is widening rapidly, the Government of India is encouraging private companies to participate in the power generation. The opening of power sector to private investment also induces competition into the market and may be considered as an initial step in the restructuring of electricity market. This may also enhance the reliability of the system.

Power purchase from IPPs would have an effect of altering the utilities power generation- and fuel- mix depending upon the power purchase agreement (PPA) and the type of power plants used by IPPs. As the environmental emissions are directly related to generation- and fuel- mix, the IPPs are bound to have an impact on environment.

While selecting the generating plant some of the key factors considered by IPPs are capital cost, recovery period, unit size, efficient technology, plant utilization factor. Most of the Power Purchase Agreement (PPA) of IPPs guarantees a minimum level of utility purchase of IPP power, which could change the loading order of utility power plants. Plant load factor of IPPs changes according to PPA. There are number of other factors that could influence the generation mix, consequently emission of air-pollutant of utility with electricity purchase from IPPs. Fixed minimum load conditions can create operating problems for utilities when the base load generation is high compared to the demand. In addition, IPPs may employ a unit size that is different to that of the electric utility.

The aim of this chapter is to examine the effect of IPPs on environmental pollutions and cost of generation expansion. Studies have been carried out to establish impact of IPPs on electricity price, generation mix, capacity mix and reliability of the whole system. In

addition, sensitivity analyses with respect to some key parameters associated with IPPs have also been conducted. The studies have been carried out on the data of the Northern Regional Electricity Board (NREB) system of India.

2.2 METHODOLOGY

An Integrated Resource Planning Analyses (IRPA) package, supplied by the Asian Institute of Technology, Thailand and CPLEX [25] linear optimizer have been used for the analysis of the least cost generation expansion planning. The IRPA package computes total cost including installation cost, O&M cost, fuel cost and emission levels of different pollutants including GHG (only CO_2 considered in the present study). The formulation of IRPA is based on the least cost optimization criteria. The formulation is given in Appendix A. the objective of IRPA is to determine the least cost generation expansion plan that minimizes the total cost of power generation from existing and candidate power plants over the planning horizon. In the IRPA, the least cost optimization has been considered along with following main system constraints:

Demand Constraint: This constraint ensures that the sum of power generation by all power plants (existing and candidate) should be equal to or greater than total projected power demand during the planning horizon.

Reliability Constraint: This constraint imposes limit on the power demand from all the plants (existing and candidate) to be greater than or equal to the sum of the power demand and the reserve margin in each year of the planning horizon.

Annual Energy Constraint: Annual energy constraint are included to limit the energy generation of each thermal plant according to the capacity, availability and time required for schedule maintenance of the plant.

Hydro Energy Constraint: The hydro energy constraint is defined for each hydro plant such that its total energy output in each season should not exceed the pre specified energy limit.

Fuel or Resource Availability Constraint: These constraints are defined to ensure that the energy generation from power plants by each fuel type does not exceed the maximum level possible with the fuel or resource available during the planning horizon.

Annual Emission Constraint: The annual emission level of each pollutant from total power system should not exceed the pre-specified value of each year.

DSM Constraint: The difference of number of efficient appliances retired in a year must not exceed the product of population of the available appliances and penetration-rate of the DSM program for any type of consumer in that year.

The mathematical formulation of these constraints is provided in appendix A.

In order to assess the environmental implications of IPPs, two least cost generation expansion planning were carried out: One without taking IPP plants into consideration and the other with IPP plants introduced in a particular year of the planning horizon. IPP plants are assumed to be connected to the grid at generation level and, together with the utility generators, supply the total load. Also, these two planning cases were analysed under both traditional resource planning (TRP) and integrated resource planning (IRP) perspectives. A flowchart showing the methodology adopted is shown in fig. 2.1.

Total emissions of air pollutants (CO_2, SO_2, NO_X) are estimated for both the cases (without IPP and with IPP) during the planning horizon using the optimal generation mix for the respective cases. The total emission for both the cases would be compared to estimate the effect of IPPs on environmental emissions.

Change in emission from the power sector due to the electricity purchase from IPPs can be expressed as:

$$\nabla E = E_1 - E_2 - E_3$$

where, E_1 = Total emission from utility in the base case

E_2 = Total emission from utility generation in the IPP case

E_3 = Total emission from IPP plants.

With the introduction of IPPs, the generation mix of the utility changes depending on the characteristics of the IPP plant and amount of electricity purchase, which in turn changes the environmental emission. For example, if IPP plant was of gas-fired combined cycle type then there would be a net reduction in the total emission of CO_2 but when it is a coal-based plant, it will aid to the total emission of air pollutants. The IPP plants can be classified into two types based on their operational flexibility: dispatchable and non-dispatchable. A dispatchable plant would be preferred over the other due to its high operational flexibility and hence the reduction in fixed O&M cost.

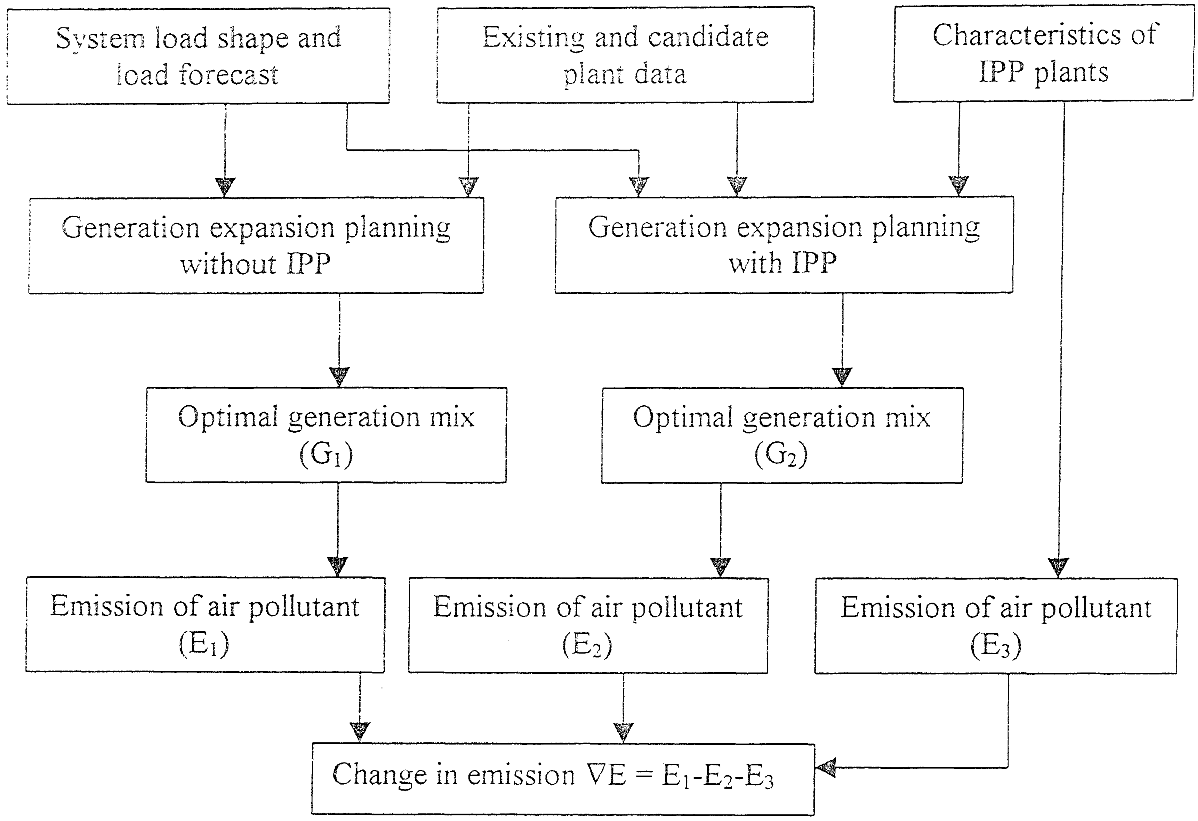

Fig. 2.1: Flowchart to calculate effects of IPP plant on environmental emission

2.3 INPUT DATA AND ASSUMTIONS

Indian Electricity sector consists of five Regional Electricity Boards (REBs) further divided into State Electricity Boards (SEBs). These REBs exist to promote the integrated operation between SEBs of that region. The five REBs are listed as [3]:

1. Northern Regional Electricity Board (NREB) having HQs at New Delhi
2. Southern Regional Electricity Board (SREB) having HQs at Bangalore
3. Western Regional Electricity Board (WREB) having HQs at Mumbai
4. Eastern Regional Electricity Board (EREB) having HQs at Calcutta
5. North-Eastern Regional Electricity Board (NEREB) having HQs at Shillong

2.3.1 Overview of the Northern Regional Electricity Board (NREB) System, India

This study utilizes the data of NREB system, India consisting of eight states namely Rajasthan, Punjab, Delhi, Haryana, Himachal Pradesh, Uttar Pradesh (including Uttaranchal) and Jammu & Kashmir. Each state has its own electricity boards.

India has seen a significant progress in the electric sector since independence. The installed generating capacity has increased sixty-one fold and annual electricity generation by ninety-three folds between 1947 and 1996. But still, there exists a wide gap between demand and supply. For NREB system, peak demand and energy shortage are respectively 16.9% and 8.1%.

During 8^{th} plan i.e. 1992-1997 generating capacity addition of 30538 MW at central level and 9849 MW in NREB has been completed. Installed generating capacity at the end of 8^{th} plan was 86156 MW for India and 24568 MW for NREB. The installed capacity of NREB as on March 2000 was 25847 MW in total. At the end of 1997, private sector share in total installed capacity of India was 4650 MW i.e. 5.4% [3]. There are 160 thermal power plant units and 230 hydro power plant units in NREB. They are given in appendix B. Installed capacity of different types of plants, as of north zone, is shown in Table 2.1 for the NREB system.

Table 2.1: Present installed capacity in NREB

Plant Type	Generation (MW)
Thermal	17239
Hydro	7698
Nuclear	910

The principal transmission voltages in the NREB are 400 kV, 220 kV and 132 kV/110 kV. At the end of 1995 – 1996, the lines in operation were 34279 km. of 400 kV, and 76930 km. of 220 kV in the country. A large network of transmission lines exists at lower voltage also. Apart from Extra High Voltage (EHV) alternating current transmission lines, high voltage direct current lines are also there and the first being the 500 kV Rihand – Dadri line over a distance of 817 km [3].

The transmission and distribution losses in the country stood at about 21% in 1995-1996. This level of transmission and distribution losses is considered to be very high and efforts are being made to reduce the losses. CEA utilizes the power reliability indices as Loss of Load Probability (LOLP) of 2% and Energy not Served (ENS) not to exceed 0.15%.

2.3.2 Electricity demand, energy requirement and load factor data

The present study has considered a planning horizon of 15 years starting from year 2003 to 2017. Electricity demand, energy requirement and load factor forecasting for NREB system has been taken from 16th Electric Power Survey (EPS) of India [26]. In IRPA, demand forecast was required to be projected up to the year 2017. However, the forecasted data was available only up to 2012. So, electricity demand and energy requirement in between the years i.e. between 2001-02 & 2006-07, 2006-07 & 2011-12, have been calculated through interpolation of the EPS data and beyond 2012, up to 2017 is calculated by extrapolation. Detailed forecast of peak demand, energy requirement and load factor for each year in the planning horizon is shown in Table 2.2.

Table 2.2: Electricity Demand, Energy Requirement and Load Factor data

Year	Peak Load (MW)	Energy Requirement (GWh)	Load Factor (%)
2003	27085.45	168483.4	71.01
2004	28988.88	180271.7	70.99
2005	31026.07	192884.7	70.97
2006	33206.42	206380.2	70.95
2007	35540.00	220820.0	70.93
2008	38001.41	236096.6	70.92
2009	40633.30	252430.0	70.92
2010	43447.47	269893.3	70.91
2011	46456.53	288564.8	70.91
2012	49674.00	308528.0	70.90
2013	53075.84	329628.1	70.90

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2012	49674.00	308528.0	70.90
2013	53075.84	329628.1	70.90

2014	56710.66	352171.3	70.89
2015	60594.40	376256.1	70.88
2016	64744.10	401988.2	70.88
2017	69178.00	429480.0	70.87

2.3.3 Assumptions used in the analyses

In the present study, most of the data are consistent with the norms used in India for power generation expansion planning. The assumptions made in this study are listed below:

1. The planning horizon is taken as 2003-2017, base year is considered as 1998 and discount rate as 10%. Reserve margin is taken as 5% for all the years. Transmission loss rate is taken as 4%.
2. Twenty blocks are taken in one season and two seasons are considered in one year. Season 1 is of total 92 days (July, August and September) and season 2 (rest of the months) consisting of total 273 days. All costs are taken for the base year of 1998.
3. Minimum operating capacity is taken as 30% of the installed capacity. Operating cost is taken as 1% of the total capital cost and fixed operating and maintenance (O&M) cost as 2.5% for thermal plants. Operating cost for hydro plants is assumed to be zero and fixed O&M cost is taken as 1.5% of the total capital cost.
4. In DSM data, replacement of incandescent bulbs by Compact Fluorescent Lamps (CFL) is derived from the available references [27,28,39,30,31,32]. Breakdown of GLS lamps of different power ratings i.e. 40, 60, 100 watts and others in residential sector are assumed in the ratio of 45:35:15:5. Installed GLS lamps in different sectors i.e. domestic, commercial and industrial are assumed in the ratio of 70:25:5. This ratio is just an intelligent assumption based on survey report done in small region of Uttar Pradesh and Gujrat, which are two states in India [31,33].

Total ten types of fuels have been taken for thermal plants, which are six types of coal based on coal cost, gas, nuclear, lignite and oil. Four types of thermal power plants with one IPP plant based on coal and twenty-three types of hydro power plants including four hydro IPP plants are considered as candidate plants. All considered thermal and hydro candidate plants are given in appendix B. In the NREB, there are eight existing thermal IPP plant units and eight existing hydro IPP plant units. These all existing and candidate IPP power plants

are given in Appendix C. In the present study minimum plant load factor for IPP was taken as 68.5% [19,34]

2.3.4 DSM options

Five types of demand side options are considered for the present study, three in the residential sector and two in the agricultural sector. These are listed in Table 2.3.

Table 2.3: DSM options

Sector	*DSM options*
Residential	DSM 1: Replacement of 100 W incandescent bulb by 20W CFL DSM 2: Replacement of 60W incandescent bulb by 11W CFL DSM 3: Replacement of 40W incandescent bulb by 9W CFL
Agriculture	DSM 4: Replacing inefficient pumps by efficient ones DSM 5: Partial rectification of pumps

End use efficiency improvement and Demand Side Management (DSM), offer new hope to Indian utilities to bring the demand and supply of electricity closer to balance, when the country is experiencing an overall energy deficiency with peak demand remaining unserved.

In 1991-1992, the domestic sector consumed 17% of the total electricity sales in the country. Both the number of consumers and per capita consumption of electricity in the domestic sector are growing at fast rate, and the share of the Domestic sector in total electricity consumption is estimated to increase to 36.6% by 2006-2007. Lighting accounts for 28% share of total domestic energy consumption. Present lighting use in the domestic sector is largely from incandescent lamps and to some extent from fluorescent lamps. In the domestic sector, there exists a very strong case for substituting low efficiency incandescent lamps with high efficiency fluorescent lamps, while maintaining or increasing the level of lumen output [35]. In 1998, number of GLS lamps in northern region was 79.24 million [28]. Thus, there exist a large potential to save energy by replacing GLS with CFL. In the present study, DSM data for the residential sector are derived from different available literature. Chronological load curve of the residential sector is based on survey report done for Gujarat State Electricity Board (GSEB) [31].

Food grain in India, at present, is around 200 million tons. 5 million tons are to be added every year to take care of the increase in population. Land area available for cultivation is about 200 million hectare. Not even 25% of this land area are under irrigation. Out of irrigated land, about 50% is lift irrigated using around 15 million small pump sets of 1 kW to 5 kW capacity. About 60% are driven by electric motors and rest by diesel engines. Roughly one million pumps are added every year. The share of electric agro-pump sets in total electric power consumption of the nation increased from 17.67% during 1981 to 26% during 1991 and is steadily rising. Considering that this is an annual average and that agro pump sets are used more only during certain seasons and not through out the year, they present a major load on the power grid, at times causing great strain on the power system. The installed base of electrically operated irrigation pump sets today is around 3.8 millions in NREB with average rating of pump sets from 2.2 to 3.7 kW [36]. Agriculture pumps account for 23% of electricity use, which has the second highest share of electricity end use after industrial motors [35]. Thus, rectification of agriculture pumps is a promising demand side option. Complete rectification of agricultural pumps includes changing of inefficient electric pumps with efficient pumps, which increases the efficiency figure by 65.2%. Partial rectification of agriculture pumps include replacement of local foot valve by low resistance foot valve, substitution of G.I. pipe in suction line by low friction RPVC pipe of proper diameter and substitution of G.I. pipe in delivery line by low friction RPVC pipe of proper diameter, which increase the efficiency by 26.7% [36]. Chronological load curve for the agriculture sector is taken from a TERI report based on study done in Uttar Pradesh [33]. The detailed data for the DSM is shown in Appendix E.

2.3.5 Description of cases

The generation planning studies were carried out for the following four different cases.

1. Traditional Resource Planning (TRP) without any IPP plant (The TRP cases do not include any DSM option).
2. Traditional Resource Planning with IPP plants.
3. Integrated Resource Planning (IRP) without any IPP plant (The IRP cases include the DSM options).
4. Integrated Resource Planning with IPP plants.

Sensitivity analyses have been carried out with respect to the following important parameters associated with IPPs to assess the impact of those variations on the total planning of power sector. The sensitivity analyses have been carried out for both TRP and IRP cases:

1. Changes in Operating Mode (Minimum Operating Capacity) of IPP Plants to

50%, 60%, 70%, 80%, 90%

2. Unit Size of IPP Plants:

Bigger unit, smaller unit

3. Changes in Plant Availability Factor of IPP Plants to

0.5, 0.6, 0.7, 0.8, 0.9

4. Amount of Electricity Purchase from IPPs

Twice of the existing, four times of the existing, six times of the existing, eight times of the existing

5. Duration of Contract

5, 10, 15 years

2.4 RESULTS AND DISCUSSIONS

2.4.1 Utility Planning Implications

- **Capacity mix and Generation mix**

Table 2.4 shows capacity mix by plant types for both the TRP and IRP cases. It shows that, during the planning horizon, with the introduction of IPPs, the hydrothermal mix increases by 1.9% for TRP case and 1.8% for IRP case. This is due to the fact that all candidate IPPs which got selected were of hydro type. Candidate thermal IPP being of coal6 type was not selected. The hydrothermal mix is highest in 2007 as all the candidate hydro plants are appearing in this year. The capacity avoided after the introduction of IPPs is 158 MW in both the cases.

Table 2.4: Capacity mix by plant types

Generation Expansion Planning Case		Capacity mix (%) Hydro	Coal	CCGT	Nuclear	Lignite	Total Capacity (MW)
TRP without IPP	2003	36.7	41.5	17.2	3.2	0.7	33278.7
	2007	40.7	41.4	13.7	2.5	1.0	43175.7
	2012	35.2	52.0	9.8	1.8	0.7	60310.7
	2017	29.9	56.3	8.2	4.8	0.5	84228.7
TRP with IPP	2003	36.7	41.5	17.2	3.2	0.7	33278.7
	2007	43.0	39.5	13.5	2.4	1.0	44005.7
	2012	37.8	47.8	9.8	3.4	0.7	60402.7
	2017	31.8	55.2	7.3	4.8	0.5	84070.7
IRP without IPP	2003	37.3	42.1	15.9	3.2	0.7	32778.7
	2007	41.7	40.0	12.9	3.7	1.1	42175.1
	2012	38.2	45.9	11.0	3.7	0.8	56430.7
	2017	33.2	46.1	17.1	2.7	0.6	75728.7
IRP with IPP	2003	37.3	42.1	15.9	3.2	0.7	32778.7
	2007	44.2	38.8	12.8	2.5	1.1	42258.2
	2012	41.0	43.5	10.6	3.7	0.8	56112.7
	2017	35.4	43.5	17.4	2.7	0.6	75570.7

Table 2.5 shows the generation mix of all types of plant for the TRP and IRP cases. Generation mix of hydro and CCGT plants increases with the introduction of IPPs and the share of coal based plant decreases considerably in both the cases. The share of nuclear and lignite remains same at the end of the planning horizon. Total generation in GWh remains the same in each year of planning horizon for the cases with and without the IPPs in both TRP and IRP cases. However, in the IRP case, there is an avoidance of 107795.7 GWh of generation over the TRP case due to the demand side management.

Table 2.5: Generation mix by plant types

Generation Expansion Planning Case		Generation mix (%)					Total Generation (GWh)
		Hydro	Coal	CCGT	Nuclear	Lignite	
TRP without IPP	2003	28.6	49.7	16.6	3.4	0.8	168348.3
	2007	30.2	49.9	15.4	2.6	1.3	220897.7
	2012	26.8	63.6	6.4	1.8	0.9	308747.1
	2017	21.4	68.2	4.4	5.1	0.6	429973.5
TRP with IPP	2003	28.6	49.7	16.6	3.4	0.8	168348.3
	2007	32.8	48.4	14.3	2.6	1.3	220897.7
	2012	28.9	58.4	7.7	3.6	0.9	308746.7
	2017	22.9	66.7	4.3	5.1	0.6	429973.5
IRP without IPP	2003	29.6	51.4	13.8	3.5	0.9	162821.6
	2007	32.2	50.0	11.8	4.0	1.3	207571.2
	2012	32.7	55.1	6.5	4.3	1.1	257050.5
	2017	28.5	55.7	11.2	3.4	0.9	322177.8
IRP with IPP	2003	29.6	51.4	13.8	3.5	0.9	162821.2
	2007	34.5	48.4	12.3	2.7	1.3	207571.2
	2012	35.2	52.2	6.9	4.3	1.1	257050.5
	2017	30.6	52.9	12.0	3.4	0.9	322177.8

➢ **Technology options selected**

Table 2.6 shows that all available hydro plants get selected for each of the considered cases as these have less O&M cost and zero fuel cost. Introduction of IPPs decreases the number of coal 6 types of plants for the TRP case but for the IRP case it is not selected in either scenario. In IRP cases, a sharp decrease in number of coal 4 and nuclear plants and a considerable increase in CCGT plants has been observed as compared to the TRP cases. The only candidate thermal IPP at Jawaharpur is not selected in any of the cases due to its high cost.

Table 2.6: Technology options (Number of units) selected

	TRP without IPP	TRP with IPP	IRP without IPP	IRP with IPP
Coal 4	60	60	38	34
Coal 6	3	1	0	0
CCGT	9	6	33	34
Nuclear	6	6	2	2
Jawaharpur TPP	-	0	-	0
Hibra	2	2	2	2
K.Wangtoo	-	4	-	4
Srinagar HEP	-	4	-	4
Palamaneri	4	4	4	4
Budhil	2	2	2	2
L.Nagpala	2	2	2	2
D. Sunda	-	2	-	2
Kuther	2	2	2	2
A.Duhangan	-	2	-	2
Uhl st. III	2	2	2	2
M.Bali	4	4	4	4
T. Vishnugadh	3	3	3	3
Parbati III	3	3	3	3
Dhauliganga II	3	3	3	3
Kishanganga	3	3	3	3
Kotlibhel	4	4	4	4
Uri II	4	4	4	4
Bursar	4	4	4	4
S.Kandi	1	1	1	1
Sewa st II	2	2	2	2
Pakhaldul	4	4	4	4
Kishau	5	5	5	5
Parbati I	3	3	3	3

- **Capacity utilization of the system**

Table 2.7 shows capacity utilization of the system for each planning year and also their average value for all the cases. Average capacity utilization shows a very small increase with the introduction of IPPs for both the TRP and IRP cases. Average capacity utilization for the TRP cases is more than the respective IRP cases.

Table 2.7: Capacity utilization of the system

Year	Generation Expansion Planning Cases			
	TRP without IPP	TRP with IPP	IRP without IPP	IRP with IPP
2003	57.75	57.75	57.08	57.08
2004	56.71	56.71	55.59	55.59
2005	57.51	57.51	56.68	56.68
2006	57.09	57.09	56.42	56.42
2007	58.34	57.24	56.82	56.71
2008	58.23	58.36	55.99	56.43
2009	58.16	58.05	55.75	55.64
2010	58.10	58.55	55.45	55.45
2011	58.45	58.36	54.80	54.81
2012	58.35	58.26	54.01	54.23
2013	58.21	58.26	53.41	53.61
2014	58.11	58.30	53.11	53.25
2015	58.20	58.27	52.72	52.74
2016	58.24	58.32	52.15	52.27
2017	58.16	58.27	51.57	51.68
Average	58.05	58.06	54.44	54.51

- **Reliability of electricity generation system**

Table 2.8 exhibit relative comparison of reliability expressed in terms of unserved energy in MWh of electricity generation system each year and also its average value for all the considered cases. Average unserved energy has decreased with the introduction of IPPs

for both the TRP and IRP cases. Also average unserved energy for the TRP cases is less than that for the IRP cases.

Table 2.8: Reliability of the system

Year	Unserved Energy (MWh)			
	TRP without IPP	TRP with IPP	IRP without IPP	IRP with IPP
2003	146.544	146.544	206.613	206.613
2004	2.876	2.876	3.873	3.873
2005	4.845	4.845	31.820	31.820
2006	1.229	1.229	14.419	14.419
2007	6.730	0.379	5.333	1.613
2008	23.008	13.038	5.775	6.027
2009	6.471	1.750	26.142	14.293
2010	1.581	1.499	17.669	12.065
2011	0.433	0.156	6.190	3.705
2012	0.502	0.232	2.508	1.599
2013	0.510	0.172	17.230	8.179
2014	0.308	0.145	18.723	11.910
2015	0.077	0.032	0.922	0.536
2016	0.126	0.100	0.047	0.013
2017	0.016	0.013	0.275	0.137
Average	8.539	7.274	18.963	16.147

- **Sensitivity analyses**

- **Change in operating mode (Minimum operating capacity):**

Table 2.9 shows effect of change in minimum operating capacity (MOC) of the IPPs on capacity mix of the considered plant types for TRP and IRP cases. The MOC of the IPPs was varied from 50% to 90%. However, for the MOC above 70% the solution becomes infeasible. As shown in this table, change in minimum operating capacity does not have any significant effect on the capacity mix. For the TRP cases & with 70% MOC, the capacity mix of hydro and coal decreases slightly, but capacity mix of CCGT decreases slightly while

that of nuclear and lignite remains the same. For the IRP cases, only at 50% and 70% MOC values, an increase in the capacity mix of coal plants and decrease in that of nuclear plants are observed.

Table 2.9: Effect of change in MOC of IPPs on capacity mix

Generation Expansion Planning Case			Capacity mix (%) Hydro	Coal	CCGT	Nuclear	Lignite	Total Capacity (MW)
TRP	50%	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	31.8	55.2	7.3	4.8	0.5	84070.7
	60%	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	31.8	55.2	7.3	4.8	0.5	84070.7
	70%	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	31.7	55.0	7.6	4.8	0.5	84320.7
IRP	50%	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	35.4	44.8	17.4	1.4	0.6	75570.7
	60%	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	35.4	43.5	17.4	2.7	0.6	75570.7
	70%	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	35.4	44.8	17.4	1.4	0.6	75570.7

Table 2.10: Effect of change in MOC on av. unserved energy and av. capacity utilization

Generation Expansion Planning Case	Av. Unserved Energy (MWh)		Av. Capacity utilization (%)	
	TRP	IRP	TRP	IRP
50%	6.868	16.139	57.99	54.62
60%	6.788	16.174	57.96	54.55
70%	7.288	16.288	58.00	54.61

Table 2.10 shows effect of change in minimum operating capacity of IPPs on average unserved energy and average capacity utilization for the TRP and IRP cases. There is no significant effect of change in minimum operating capacity of IPPs on reliability and capacity utilization. Average unserved energy is minimum for the minimum operating capacity of 60% for the TRP case and for the 50% for the IRP case.

- **Unit size of IPPs**

In the case of bigger unit size, one single unit at an IPP plant was considered with the capacity of that unit increased to the total power supposed to be generated by that plant. In the case of smaller unit size, at each IPP plant, two units of smaller capacity has been deployed with the total power generated by that IPP remaining unchanged. Table 2.11 shows effect of change in unit size of IPPs on capacity mix of considered plant types for TRP and IRP cases. Change in unit size of IPPs also does not have much significant effect on the capacity mix of different plants. A small variation was observed in capacity mix of coal and CCGT plants only for the TRP cases, while for the IRP cases, the capacity mix increases for coal plants at the expense of the nuclear plants. Total capacity increases with the change in unit size for the TRP case but it remains same for the IRP case. Table 2.12 shows that both the average unserved energy and average capacity utilization both has increased with the change in unit size. The increase is more in the case of bigger size of unit.

Table 2.11: Effect of change in unit size of IPPs on capacity mix

Generation Expansion Planning Case			Capacity mix (%)					Total Capacity (MW)
			Hydro	Coal	CCGT	Nuclear	Lignite	
TRP	Bigger units	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	31.6	55.1	7.6	4.8	0.5	84200.7
	Smaller units	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	31.7	55.6	7.0	4.8	0.5	84320.7
IRP	Bigger units	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	35.4	44.2	17.4	2.1	0.6	75570.7

Table 2.12: Effect of change in unit size on av. unserved energy and av. capacity utilization

	Av. Unserved Energy (MWh)		Av. Capacity utilization (%)	
	TRP	IRP	TRP	IRP
Bigger unit	7.973	20.093	58.14	54.58
Smaller unit	7.936	17.481	58.10	54.58

- **Change in plant availability factor:**

Table 2.13 shows effect of change in plant availability factor of IPPs on capacity mix of the considered plant types for the TRP and IRP cases. The plant availability factor was varied from 0.5 to 0.9 in steps of 0.1. However, for the plant availability factor values 0.5 and 0.6 value, no feasible solution was found. With the increase in this factor, total capacity of generation reduces and it is minimum for the value 0.9 for both the TRP and IRP cases. Capacity mix of coal decreases, that of CCGT increases. For the IRP case, the capacity mix of both coal and CCGT plant increases as the plant availability factor was increased. From Table 2.14 it is observed that unserved energy is minimum and capacity utilization is maximum for plant availability factor of 0.9. Hence, the high availability factor makes the system more and more reliable and increases the utilization of the system too.

Table 2.13: Effect of change in plant availability factor on capacity mix

Generation Expansion Planning Case			Capacity mix (%)					Total Capacity (MW)
			Hydro	Coal	CCGT	Nuclear	Lignite	
TRP	0.7	2003	36.5	41.1	17.8	3.2	0.7	33528.7
		2017	31.5	54.7	8.2	4.8	0.5	84820.7
	0.8	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	31.6	54.8	7.9	4.8	0.5	84570.7
	0.9	2003	36.7	41.5	17.2	3.2	0.7	33278.7

		2017	31.9	54.7	7.7	4.8	0.5	83820.7
IRP	0.7	2003	37.0	41.8	16.5	3.2	0.7	33028.7
		2017	35.0	45.1	17.6	1.4	0.6	76320.7
	0.8	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	35.3	44.7	17.7	1.4	0.6	75820.7
	0.9	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	35.5	44.3	17.8	1.4	0.6	75320.7

Table 2.14: Effect of change in availability factor on av. unserved energy and av. capacity utilization

	Av. Unserved Energy (MWh)		Av. Capacity utilization (%)	
	TRP	IRP	TRP	IRP
0.7	9.892	21.767	57.51	54.00
0.8	9.806	21.363	57.81	54.45
0.9	5.517	11.886	58.38	54.80

- **Amount of electricity purchase:**

Table 2.15 shows the effect of change in the amount of electricity purchase from IPPs on capacity mix of the considered plant types for the TRP and IRP cases. For the purpose of study, the electricity purchase from existing and candidate IPPs were increased by increasing the installed capacity of existing and candidate IPPs two times, four times, six times, eight times of their present value. To realize this fictitious case, plant capacities were correspondingly increased. With the increase in purchased amount, the total capacity of the utility system drops off quickly. The share of hydro generation also increases in the capacity mix with the decrease in coal plants as most of the candidate IPP plants considered are of hydro type. An increase in the capacity mix of lignite and CCGT plants is also observed. Table 2.16 presents its effect on average unserved energy and average capacity utilization. It clearly shows that the unserved energy decreases and hence enhancing the reliability of the system, but at the same time it decreases the capacity factor of the system and it may be considered as a negative aspect of increasing the amount of electricity purchase.

Table 2.15: Effect of change in amount of electricity purchase from IPPs on capacity mix

Generation Expansion Planning Case			Capacity mix (%)					Total Capacity (MW)
			Hydro	Coal	CCGT	Nuclear	Lignite	
TRP	Two times	2003	38.3	41.6	14.9	3.1	1.3	33764.7
		2017	34.7	55.3	6.2	2.5	1.1	83967.7
	Four times	2003	38.5	39.1	16.4	2.9	2.4	37236.7
		2017	40.0	48.6	7.6	1.3	2.2	83161.7
	Six times	2003	38.6	37.0	17.8	2.6	3.3	40708.7
		2017	44.2	42.0	8.9	1.3	3.3	83175.7
	Eight times	2003	38.8	35.3	18.9	2.4	4.1	44180.7
		2017	48.2	35.7	10.2	1.3	4.3	83969.7
IRP	Two times	2003	38.3	41.6	14.9	3.1	1.3	33764.7
		2017	38.6	40.3	18.2	1.4	1.2	75467.7
	Four times	2003	38.5	39.1	16.4	2.9	2.4	37236.7
		2017	45.1	32.6	18.1	1.4	2.4	74891.7
	Six times	2003	38.6	37.0	17.8	2.6	3.3	40708.7
		2017	51.4	27.9	14.6	2.1	3.6	74985.7
	Eight times	2003	38.8	35.3	18.9	2.4	4.1	44180.7
		2017	56.2	25.9	11.4	1.4	4.8	75301.7

Table 2.16: Effect of change in amount of electricity purchase on av. unserved energy and av. capacity utilization

	Av. Unserved Energy (MWh)		Av. Capacity utilization (%)	
	TRP	IRP	TRP	IRP
Twice of existing	4.949	4.106	57.88	54.11
Four times of existing	0.075	8.678	56.33	52.66
Six times of existing	0.255	83.176	54.32	50.82

Eight times of existing	1.901	448.412	52.67	48.93

- **Duration of contract:**

Table 2.17 shows the effect of change in duration of contract on the capacity mix. In base case, the duration of contract is taken as 20 years. It can be observed from the table that the total capacity decreases with the decrease in the duration of contract. Capacity mix of hydro plants is also decreasing with an increase in the capacity mix of coal plants. Thus the hydrothermal mix decreases in this case. Table 2.18 shows its effect on unserved energy and capacity utilization. The unserved energy increases with the decrease in duration of contract. It is minimum for 15 years of PPA. Average capacity utilization remains almost same in this analysis.

Table 2.17: Effect of change in duration of contract on capacity mix

Generation Expansion Planning Case			Capacity mix (%)					Total Capacity (MW)
			Hydro	Coal	CCGT	Nuclear	Lignite	
TRP	5 years	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	30.7	56.6	7.5	4.8	0.0	84515.7
	10 years	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	30.9	56.4	7.6	4.8	0.0	84015.7
	15 years	2003	36.7	41.5	17.2	3.2	0.7	33278.7
		2017	30.7	56.6	7.5	4.8	0.0	84515.7
IRP	5 years	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	34.3	46.0	17.3	2.1	0.0	75765.7
	10 years	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	34.3	44.0	17.3	4.0	0.0	75765.7
	15 years	2003	37.3	42.1	15.9	3.2	0.7	32778.7
		2017	34.3	47.3	16.7	1.4	0.0	75765.7

Table 2.18: Effect of change in duration of contract on av. unserved energy and av. capacity utilization of the system

	Av. Unserved Energy (MWh)		Av. Capacity utilization (%)	
	TRP	IRP	TRP	IRP
5 years	10.993	24.657	58.10	54.57
10 years	7.160	19.976	58.08	54.44
15 years	6.912	15.680	58.01	54.55

2.4.2 Cost and Pricing Implications

- **Expansion costs during the planning horizon**

Table 2.19 shows comparison of discounted expansion cost for all the cases in the planning horizon at the base year of 1998. It can be observed that the total expansion cost with IPP has decreased as compared to the base case without IPP for both the TRP and IRP cases. Capital cost increases after the introduction of IPPs as their capital cost is high. There is a significant amount of saving in fuel and variable cost due to the introduction of efficient IPP plants. A slight decrease in the fixed O&M cost is also observed. Figure 2.2 shows comparison between capital cost, fuel and O&M cost, total expansion costs for all the considered cases.

Table 2.19: Expansion costs during planning horizon

Expansion costs during planning horizon (M$)	Generation expansion planning cases			
	TRP without IPP	TRP with IPP	IRP without IPP	IRP with IPP
Capital cost (1)	6142.30	6204.52	4657.26	4675.33
Fixed O&M (2)	5273.20	5253.69	4961.57	4933.07
Fuel and Variable (3)	19608.33	19282.66	15861.34	15563.86
Fuel and O&M (2+3)	24881.53	24536.35	20822.91	20496.93
Sub total (1+2+3)	31023.83	30740.87	25480.17	25172.26
DSM cost (4)	0	0	707.5	707.5

Table 2.21: Effect of change in minimum operating cost of IPPs on expansion costs

		Capital cost (M$)	Fuel and O&M (M$)	Total cost including DSM cost (M$)
50%	TRP	6241.85	24503.70	30745.56
	IRP	4535.19	20610.00	25852.72
60%	TRP	6279.61	24476.08	30755.70
	IRP	4620.50	20551.52	25879.53
70%	TRP	6251.01	24508.88	30759.90
	IRP	4541.00	20629.64	25878.15

- **Change in unit size**

It is evident from Table 2.22 that by changing unit size total expansion cost increases in comparison to base case (see Table 2.19) but there is a considerable drop in the capital cost for both the cases. For the smaller unit, the decline in capital cost is less than that for the bigger unit. For IRP case smaller unit case, total expansion cost also reduces.

Table 2.22: Effect of change in unit size of IPPs on expansion costs

		Capital cost (M$)	Fuel and O&M (M$)	Total cost including DSM cost (M$)
Bigger unit	TRP	5774.20	25090.03	30864.24
	IRP	4584.08	20590.24	25881.83
Smaller unit	TRP	5964.59	24850.93	30815.53
	IRP	4593.90	21447.13	25868.54

- **Change in plant availability factor**

As shown in Table 2.23, for TRP cases, changing the plant availability factor of IPPs to 0.7 increases capital cost, fuel and O&M cost and total cost. However, after further increase beyond 0.7, a reduction is observed in the total expansion costs. For the IRP cases, similar conclusions are drawn from the table.

Table 2.23: Effect of change in plant availability factor on expansion costs

		Capital cost (M$)	Fuel and O&M (M$)	Total cost including DSM cost (M$)
0.7	TRP	6434.73	24540.7	30975.44
	IRP	4781.33	20710.9	26199.75
0.8	TRP	6319.80	24401.01	30720.83
	IRP	4599.95	20589.35	25896.81
0.9	TRP	6048.07	24503.16	30551.24
	IRP	4443.68	20558.94	25710.12

- **Change in electricity purchase**

By changing the amount of electricity purchase from IPPs, the total expansion cost changes significantly (see Table 2.24). The capital cost falls down sharply with the increase in the electricity purchase from IPPs as now more power is being purchased from the existing IPPs. An important conclusion drawn from this analysis is that if the electricity purchase from the IPPs increases, electricity can be made available at a much lower price.

Table 2.24: Effect of change in amount of electricity purchase from IPPs on expansion costs

		Capital cost (M$)	Fuel and O&M (M$)	Total cost including DSM cost (M$)
Twice of existing	TRP	5271.63	23577.34	28848.97
	IRP	3791.15	19706.78	24205.44
Four times of existing	TRP	4063.97	22775.38	26839.30
	IRP	2528.70	19185.00	22421.27
Six times of existing	TRP	3202.46	22803.26	26005.73
	IRP	1641.42	19788.63	22137.55
Eight times of existing	TRP	2307.58	23808.86	26116.4
	IRP	984.20	21308.67	23000.38

- **Change in duration of contract**

As shown in Table 2.25, decreasing the duration of the contract of IPPs increases all the costs including total expansion cost. As this contract decreases from the base value of 20 years, all the cost increases. Thus it can be concluded that increasing the duration of contract reduces the cost and hence decreases the electricity price.

Table 2.25: Effect of change in duration of contract on expansion costs

		Capital cost (M$)	Fuel and O&M (M$)	Total cost including DSM cost (M$)
5	TRP	7159.20	24815.51	31974.72
	IRP	5541.86	20885.75	27135.12
10	TRP	6679.26	24697.34	31376.61
	IRP	5203.44	20615.16	26526.12
15	TRP	6354.97	24620.17	30975.15
	IRP	4719.55	20647.16	26074.22

2.4.3 Environmental Implications

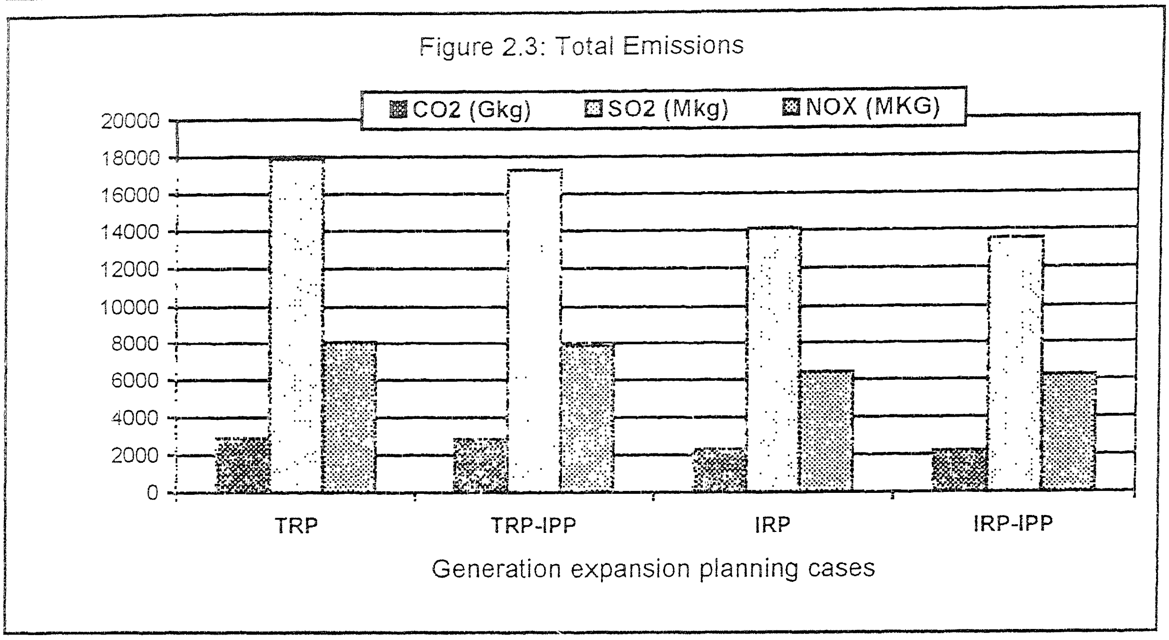
- **Total environmental emissions**

Table 2.26 shows the total CO_2, SO_2 and NO_x emission for all the considered cases in the planning horizon. From this table, it can be observed that the introduction of IPP reduces GHG (only CO_2 considered in this study) and other pollutants emission for both the TRP and IRP cases. This is mainly due to more number of hydro generation based IPPs being selected. The emissions in the IRP cases are less than those in the TRP cases. Figure 2.3 shows the comparison of total CO_2, SO_2 and NO_x emission for all the considered cases.

Table 2.26: Total environmental emissions

Emission	Generation expansion planning cases			
	TRP without IPP	TRP with IPP	IRP without IPP	IRP with IPP
CO_2 (Gkg)	2927.15	2837.10	2285.53	2200.30
SO_2 (Mkg)	17899.21	17305.56	14096.29	13549.31

NO_x (Mkg)	8067.28	7856.86	6412.73	6212.14



➢ **Sensitivity Analyses**

- **Change in minimum operating capacity:**

Table 2.27 shows that the change in minimum operating capacity of IPPs does not have any significant effect on environmental emission. Emission of carbon dioxide and other pollutants (SO_2 and NO_x) does not vary much by increase in minimum operating cost for the TRP cases. These emission decrease gradually as the MOC is increased particularly for SO_2 and NO_X. For the IRP cases, all the emissions show an increasing trend with the increase in MOC.

Table 2.27: Effect of change in MOC of IPPs on environmental emissions

Emission		50%	60%	70%
TRP	CO_2 (Gkg)	2838.10	2836.15	2827.30
	SO_2(Mkg)	17328.43	17323.54	17237.57
	NO_x (Mkg)	7858.79	7852.74	7833.53
IRP	CO_2 (Gkg)	2259.32	2221.94	2257.7
	SO_2 (Mkg)	13917.89	13687.52	13890.75
	NO_x (Mkg)	6356.07	6266.34	6350.84

- **Change in unit size:**

Table 2.28 shows that changing the size of units from the base case, irrespective of increase or decrease in their size, has increased the emission from the base level. Hence, the size of units considered in the base case is most suitable as far as the environmental emission is concerned. However this conclusion cannot be generalized. In order to have am most suitable combination of the units to reduce the environmental emission, one may have to optimize the problem on case-to-case basis by taking different possible sizes of all the candidate IPP plants. It can also be observed that the emissions are comparatively lesser in case of smaller units than in case of the bigger units for both the TRP and IRP cases.

Table 2.28: Effect of change in unit size of IPPs on environmental emission

Emission		Generation expansion planning cases	
		Bigger unit	Smaller unit
TRP	CO_2 (Gkg)	2865.43	2853.42
	SO_2 (Mkg)	17312.12	17320.99
	NO_x (Mkg)	7950.59	7907.55
IRP	CO_2 (Gkg)	2235.32	2228.91
	SO_2 (Mkg)	13762.39	13718.99
	NO_x (Mkg)	6299.34	6283.78

- **Change in plant availability:**

Table 2.29 shows that by changing the plant availability factor of IPPs, CO_2 and NO_x emission decreases by a very small amount but SO_2 emission rises considerably for the TRP case. For the IRP cases, the effect of increasing the plant availability factor is to increase the emission of GHG and other pollutants.

Table 2.29: Effect of change in plant availability factor of IPPs on environmental emission

Emission		0.7	0.8	0.9
TRP	CO_2 (Gkg)	2834.50	2837.40	2833.56
	SO_2 (Mkg)	17289.89	17423.33	17410.25

	NO_x (Mkg)	7844.94	7847.23	7849.52
IRP	CO_2 (Gkg)	2251.62	2252.39	2255.84
	SO_2 (Mkg)	13809.87	13914.05	14020.84
	NO_x (Mkg)	6334.03	6334.00	6345.41

- **Change in electricity purchase:**

Table 2.30 shows that the change in amount of electricity purchase from IPPs has significant effect on environmental emissions. Emission of CO_2 and NO_x decreases by increase in amount of electricity purchase from IPPs as the share of hydro generation has increased. But emission of SO_2 has increased with the increase in electricity purchase. This could be due to the large amount of SO_2 emissions from the existing thermal IPPs.

Table 2.30: Effect of change in amount of electricity purchase from IPPs on environmental emissions

Emission		Generation expansion planning cases			
		Twice of existing	Four times of existing	Six times of existing	Eight times of existing
TRP	CO_2(Gkg)	2781.43	2610.59	2495.00	2473.25
	SO_2(Mkg)	17607.85	17399.40	17544.70	18170.40
	NO_x(Mkg)	7701.99	7255.64	6892.75	6790.01
IRP	CO_2 Gkg)	2165.60	2038.02	1977.81	2041.37
	SO_2(Mkg)	13953.55	14122.79	14535.82	15625.66
	NO_x(Mkg)	6108.93	5728.69	5493.64	5573.19

- **Change in duration of contract:**

Table 2.31 shows that the emission of CO_2 and NO_X increases and that of SO_2 decreases with the decrease in the duration of the contract of IPPs for the TRP cases. But for the IRP cases all the emissions show an increasing trend for increased duration of contracts except in the case of 10 years contract in which SO_2 emission has decreased.

Table 2.31: Effect of change in duration of contract on environmental emission

Emission		Generation expansion planning cases		
		5 years	10 years	15 years
TRP	CO_2 (Gkg)	2865.41	2850.50	2845.77
	SO_2 (Mkg)	17088.69	17137.89	17252.58
	NO_x (Mkg)	7920.33	7888.92	7877.30
IRP	CO_2 (Gkg)	2274.52	2201.61	2265.01
	SO_2 (Mkg)	13571.46	13292.94	13843.13
	NO_x (Mkg)	6387.52	6207.51	6365.34

2.5 CONCLUSIONS

The work reported in this chapter has studied the impact of considering IPPs in the generation expansion planning on the cost and emission of GHG and other pollutants. Studies were carried out for both the traditional resource planning (TRP) and integrated resource planning (IRP) cases for the NREB system of India. On the basis of the results obtained for various cases and sensitivity analyses carried out, following conclusions can be drawn.

- With the introduction of IPPs, capacity mix of hydro plants increases with decrease in capacity mix of coal plants. Total installed capacity also reduces with the introduction of IPPs, capacity addition avoided is 158 MW in both TRP and IRP cases during the planning horizon. All candidate IPP of hydro type got selected during the planning horizon but the thermal type candidate IPP was not selected in any of the cases studied. Average capacity utilization increases and average unserved energy decreases with the introduction of IPPs for both the TRP and IRP cases.
- Introduction of IPP plants reduces CO_2, SO_2 and NO_x emission for both the TRP and IRP cases. It also reduces the fuel and O&M cost, total expansion cost but increases the capital cost. As long as the total expansion cost decreases, the IPP can have an upper hand over the other plants. Thus one can expect reduction in electricity price with the introduction of IPP plants.

- Changing minimum operating capacity of IPP plants does not have any significant effect on utility planning, total expansion cost and emission of GHG and other pollutants for both the TRP and IRP cases. Changes in capacity mix, average unserved energy, utilization factor and environmental emissions are insignificant for both the TRP & IRP cases. The emission reduces slightly with the increase in MOC. Total expansion cost increases for both TRP and IRP case.
- Changing unit size of IPPs also does not have any significant effect on capacity mix. Changing the unit size of IPPs increases the average unserved energy and average capacity utilization. Total expansion cost increases for both increase and decrease in unit size from its base value for the IRP and TRP cases. However, the capital cost decreases in all the cases. Use of smaller units also decreased the total expansion cost in the IRP case. Changing unit size has increased the environmental emissions from its base value.
- Total installed capacity decreases with increase in plant availability factor of IPPs for both the TRP and IRP cases. System becomes more reliable and capacity utilization also increases with the increase in availability factor of IPPs. Increasing the plant availability factor of IPPs up to 0.7 increases the total cost, capital and fuel and O&M costs but further increase of availability factor decreases the total cost. For the TRP case, SO_2 emission increases with other emissions (CO_2 and NO_X) showing small reduction, but for the IRP case, all emissions increases with the increase in the availability factor.
- With the increase in amount of electricity purchase from IPPs, total capacity of utility generation falls down sharply. The hydrothermal mix increases for both the TRP and IRP cases. Average unserved energy and capacity utilization of the system decrease for both the TRP and IRP cases. As expected, increasing the amount of electricity purchase from IPPs, the total cost, capital cost and fuel and O&M cost decrease significantly. Emission of GHG (only CO_2 in this study) and other pollutants (SO_2 and NO_X) also reduces.
- Decreasing the duration of the contract of IPPs decreases the total capacity of the system. The hydrothermal mix decreases with the decrease in the duration of contract. The unserved energy increases but the capacity utilization remains almost

same. Capital cost, fuel and O&M cost and total expansion cost all increases with the decrease in the contract. Emission of GHG (CO_2) and NO_X increases but that for SO_2 decreases for the TRP case. For the IRP case, all the emissions show an increasing trend.

CHAPTER 3

IMPACT OF DISTRIBUTED POWER GENERATION ON GENERATION PLANNING

3.1 INTRODUCTION

Conventionally, electrical power has been generated centrally and dispatched to the load centers through an extensive transmission and distribution network. In the recent past, a lot of interest has been shown in installing distributed power generation (DPG) plants which may eliminate the transmission & distribution losses as they are located near the load center. Moskowitz has defined distributed sources as demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that system [20].

Major portion of the load is being supplied through central generating units and DPG have been employed to supply only during the peak load period. The DPG technologies includes, for example, photovoltaic systems, fuel cells, natural gas engines, energy storage devices, wind turbines, demand side management devices, concentrating solar power collectors, geothermal energy systems, mini hydro etc. Petrie et al noted that primary source of DPG in developing countries is reciprocating engines fueled by diesel fuel or natural gas and renewable energy sources (e.g. solar, wind and hydropower) [22]. Though the participation of DPG in power generation is increasing, their environmental implications are not yet known.

In this chapter, an analysis of the environmental and utility planning implications of DPG has been provided. The analysis also includes few of the important factors associated with generation expansion planning like capacity mix, generation mix, capacity factor and unserved energy. Sensitivity analyses have also been done with respect to few parameters associated with candidate DPG plants. At the end of the chapter, cost-effectiveness and mitigating potential of individual DPG plant is also provided.

3.2 METHODOLOGY

The aim of this study is to estimate the change in environmental emissions with the introduction of DPG. DPG in this study has been treated as a fixed generation technology. The generation is fixed either due to the characteristic of technology itself (e.g., solar, wind, hydro) or its operation is limited only in the peak hour.

The methodology for this study utilizes the least cost expansion planning model as given in chapter 2. All the constraints given in chapter 2 are applicable in this case also. The mathematical formulation is given in appendix A. In order to assess the environmental implications of DPGs, first of all feasible DPG plants are identified in the system. Flowchart for identifying feasible DPG plant is shown in fig 3.1. When the avoided total generation cost with the introduction of a DPG is greater than the transmission & distribution cost for connecting that DPG to the grid, then that plant is considered to be feasible or else it is infeasible.

The feasible DPG plants are connected to the grid. The connection of DPG plants to the main grid may result in the change in DPG plant capacity factor, utility's electricity generation, generation mix, and thus total environmental emissions. To estimate the environmental implications of DPG, a procedure similar to the IPP case has been adopted. The flowchart for assessing it is shown in fig 3.2. The two scenarios considered are the base case scenario, in which DPG plants are not connected to the grid, and another scenario, in which DPG plants are connected to the grid. These two planning cases have been analyzed under the traditional resource planning (TRP) and the integrated resource planning (IRP) perspectives as in the case of IPPs.

The effects of the introduction of DPG plants on reliability, electricity price, capacity mix and generation mix have been studied. Generation system reliability is measured in terms of reserve margin, loss of load probability (LOLP), and expected energy not served (EENS).

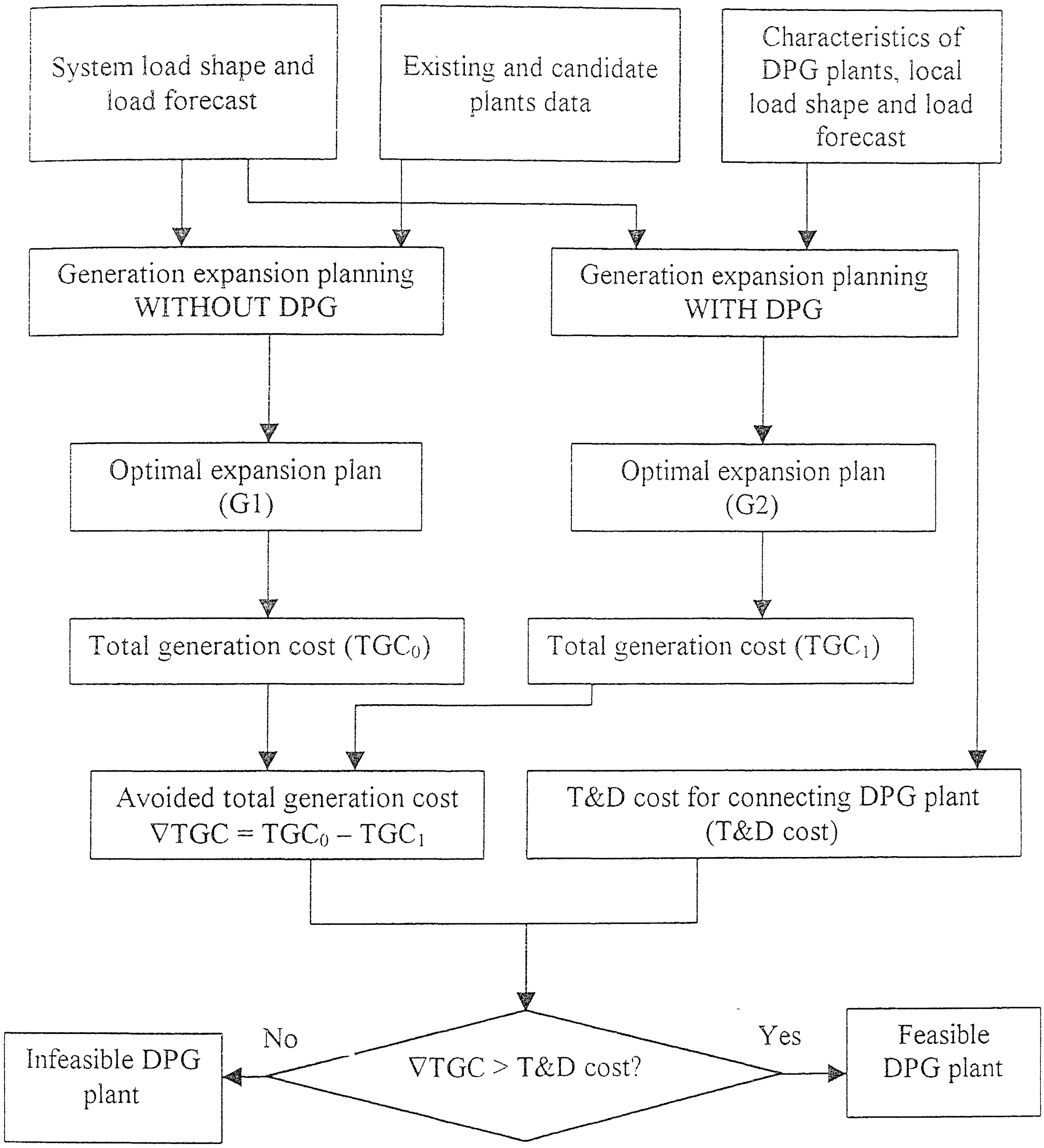


Figure 3.1: Flowchart to identify feasible DPG plants

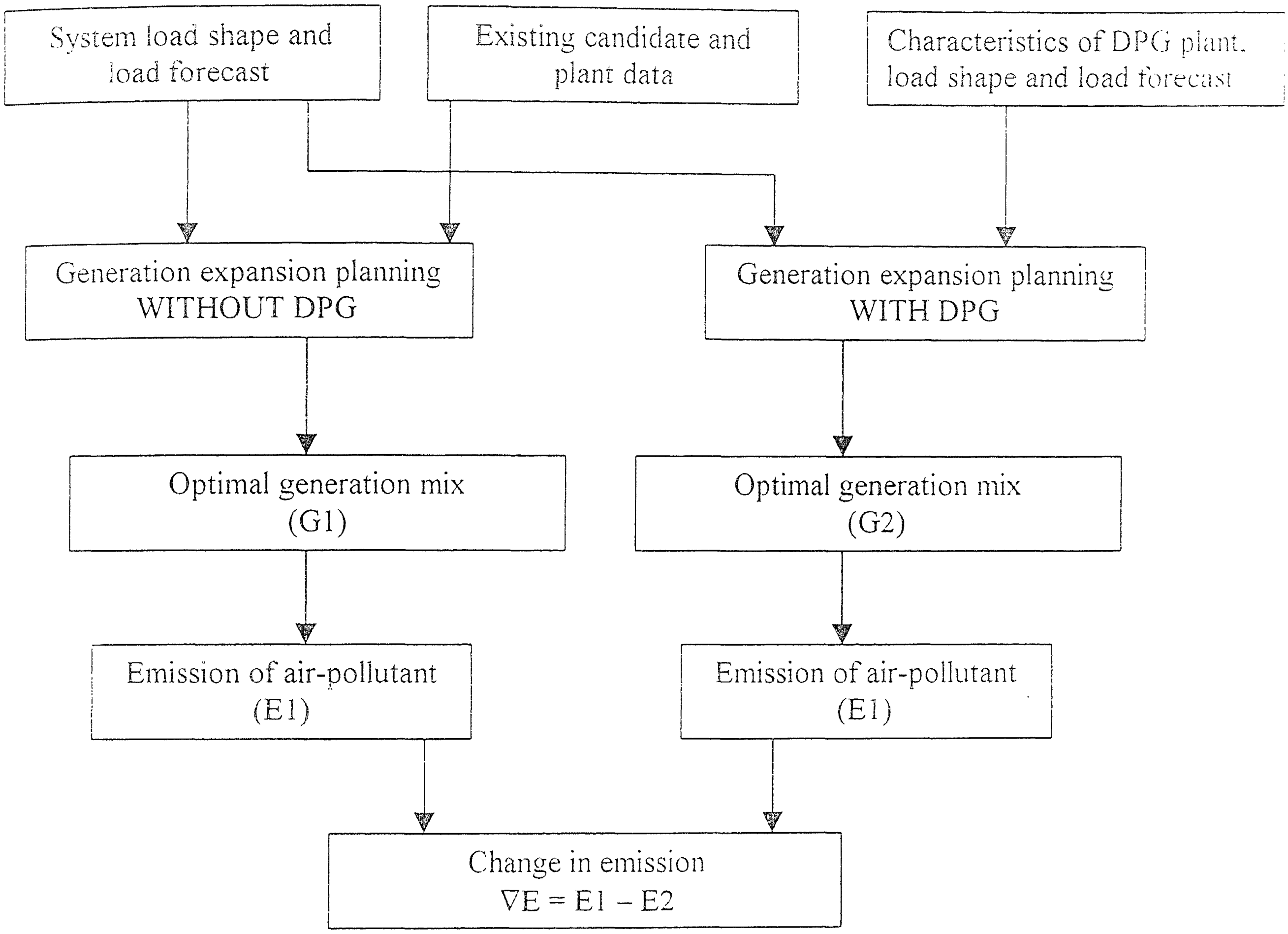


Fig. 3.2: Flowchart to calculate effects of a DPG plant on environmental emission

3.3 INPUT DATA AND ASSUMPTIONS

Generations based on renewable energy sources are gaining large momentum in India in the recent past. For example, it is having total 1080 MW of wind power generation and 42 MW from solar photovoltaic as on March 1999. A 140 MW integrated solar combined cycle (IGCC) power project at village Mathania in Jodhpur district in Rajsthan has been proposed by Ministry of Power out of which a 35 MW component is based on photovoltaic generation [3]. Assuming 0.5% land availability for wind power generation in potential area, gross potential of northern, southern, western, eastern REBs is estimated to be 1210 MW, 7600,

8020, 1020 MW [37]. Estimated potential of biomass, wind and solar power in India is given in table 3.1.

Table 3.1: Estimated potential of renewable in India

Energy Source	Estimated Potential
Wind Energy	20000 MW
Solar Energy	$5*10^{15}$ kWh/pa
Biomass	17000 MW

Source: Naidu, 1996 [38]

Though the figures in Table 3.1 seem to be very impressive, the contribution of renewable energy has not been significant enough in the overall energy scenario. The major reason for this is that most of the renewable sources are not economically viable as compared to the conventional sources.

All the data used and assumptions made in chapter 2 are also utilized in the analysis with DPG. In addition to these, the following data related to DPG are also used:

i) Existing DPG: All the existing DPG are hydro power plants. There are 28 existing DPG plants in all. Their technical data is provided in appendix D.

ii) Candidate DPG: Three kinds of candidate DPG plants based on renewable energy sources, viz. wind, solar and mini/micro hydro plants, are considered in this study. There are 500 plants of each type and each one of them is of 2 MW size. Their daily energy generation pattern and technical characteristics is given in appendix D.

3.4 RESULTS AND DISCUSSIONS

3.4.1 Utility Planning Implications

- **Capacity mix and generation mix**

Table 3.2 shows capacity mix by plant types for TRP case. As indicated in this table that with the introduction of DPG, capacity mix of coal, CCGT and PFBC decreases whereas the capacity mix of nuclear increases. Capacity mix of lignite remains same over the planning horizon. Decrease in capacity mix is mainly observed in relatively costly plants like CCGT and PFBC. PFBC is not selected at all in the alternate case i.e. the case with DPG. Capacity

mix of hydro also decreases but with the selection of candidate DPG of hydro type makes the hydrothermal mix to increase. Solar plants are not selected. All the candidate wind and micro hydro plants are selected. Total installed capacity has increased by about 100 MW with the introduction of DPG during the planning horizon.

Table 3.2: Capacity mix (%) by plant types for TRP cases

	TRP without DPG				TRP with DPG			
	2003	2007	2012	2017	2003	2007	2012	2017
Hydro	36.8	43.1	37.9	31.4	36.6	42.6	36.9	31.3
Coal	41.4	39.1	48.1	54.6	41.3	37.5	46.8	53.9
CCGT	17.2	13.7	10.3	7.3	16.4	13.0	9.4	6.7
Nuclear	3.2	2.5	2.6	4.8	3.2	3.6	3.4	4.8
Lignite	0.7	1.0	0.8	0.5	0.7	1.0	0.7	0.5
PFBC	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	-	-	-	-	0.0	0.0	0.0	0.0
Wind	-	-	-	-	0.6	0.9	1.3	1.2
BIGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Hydro	-	-	-	-	0.3	0.7	1.0	1.2
Total Capacity (GW)	33.3	43.2	60.0	84.1	33.4	43.7	60.7	84.2

Table 3.3: Capacity mix (%) by plant types for IRP cases

	IRP without DPG				IRP with DPG			
	2003	2007	2012	2017	2003	2007	2012	2017
Hydro	37.4	44.1	40.4	35.0	37.2	43.8	40.4	34.8
Coal	42.0	38.8	46.8	45.6	42.0	37.9	43.4	43.4
CCGT	15.9	12.9	9.6	17.1	15.1	12.4	9.7	16.1
Nuclear	3.2	2.5	1.9	1.4	3.2	2.5	2.8	2.1
Lignite	0.7	1.1	0.8	0.6	0.7	1.1	0.8	0.6
PFBC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

IGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	-	-	-	-	0.0	0.0	0.0	0.0
Wind	-	-	-	-	0.6	1.0	1.4	1.3
BIGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Hydro	-	-	-	-	0.3	0.7	1.1	1.3
Total Capacity (GW)	32.8	42.2	56.3	75.5	32.9	41.9	56.2	75.7

From table 3.3 for the IRP case, the similar observations are made for the capacity mix as in the case of TRP. Capacity mix of CCGT and coal decreases, that of nuclear increases, whereas for lignite it remains same with introduction of DPG. PFBC and IGCC plants are not selected in both the cases i.e. the base case and the case with DPG. Hydrothermal mix increases in the DPG case and it is much higher in the IRP case in comparison to the TRP case. All wind and hydro DPG plants are selected but no solar DPG is selected. Total capacity increases by about 200 MW over the base case.

Tables 3.4 and 3.5 show the generation mix of all the plant types for the TRP and the IRP cases, respectively. Generation mix of coal, CCGT and PFBC decreases with introduction of DPG for the TRP case. Generation mix of hydro and lignite plants increases slightly while generation mix of nuclear remains the same. For the IRP case, introduction of DPG increases the generation mix of hydro, nuclear and decreases the CCGT and coal generation mix, while for nuclear it remains same. Total generation avoided is 1.9 TWh in both the TRP and the IRP case with the introduction of DPG. It amounts to a significant saving given a very small percentage of DPG, about 2% of the total capacity. This saving is due to the avoidance of transmission and distribution losses.

Table 3.4: Generation mix (%) by plant types for TRP cases

	TRP without DPG				TRP with DPG			
	2003	2007	2012	2017	2003	2007	2012	2017
Hydro	28.7	32.3	28.9	22.6	28.7	32.3	28.6	22.7
Coal	49.7	47.0	58.5	65.9	49.8	45.7	57.6	65.8
CCGT	16.5	16.3	8.5	3.9	15.6	15.0	7.0	3.6

Nuclear	3.4	2.6	2.7	5.1	3.4	3.8	3.6	5.1
Lignite	0.8	1.3	0.9	0.6	0.8	1.3	0.9	0.7
PFBC	0:0	0.0	0.0	1.6	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	-	-	-	-	0.0	0.0	0.0	0.0
Wind	-	-	-	-	0.5	0.8	1.1	1.0
BIGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Hydro	-	-	-	-	0.2	0.5	0.6	0.8
Total Gen. (TWh)	168.3	220.9	308.7	430.0	168.0	220.2	307.4	428.1

Table 3.5: Generation mix (%) by plant types for IRP cases

	IRP without DPG				IRP with DPG			
	2003	2007	2012	2017	2003	2007	2012	2017
Hydro	29.7	34.4	34.8	30.2	29.7	34.0	34.9	30.3
Coal	51.4	48.4	56.0	55.8	51.5	47.1	52.5	52.9
CCGT	13.7	12.4	5.6	11.2	12.8	12.8	5.8	10.6
Nuclear	3.5	2.7	2.2	1.8	3.5	2.8	3.3	2.6
Lignite	0.9	1.3	1.1	0.9	0.9	1.3	1.1	0.9
PFBC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	-	-	-	-	0.0	0.0	0.0	0.0
Wind	-	-	-	-	0.5	0.8	1.4	1.4
BIGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Hydro	-	-	-	-	0.2	0.5	0.8	1.0
Total Gen. (TWh)	162.8	207.6	257.0	322.2	162.5	206.9	255.7	320.3

- **Technology options selected**

Table 3.6 shows that all the candidate hydro plants get selected for each of the considered cases. Introduction of DPG decreases the number of CCGT, coal 4 plants for both the cases whereas number of nuclear plants increases in the IRP case. PFBC, IGCC and

BIGCC are not selected for all the cases except in the case of the TRP without DPG in which two PFBC plants get selected. Solar plants do not get selected in any of the cases and all available units of wind and micro-hydro get selected for both the cases.

Table 3.6: Technology options (Number of units) selected

	TRP without DPG	TRP with DPG	IRP without DPG	IRP with DPG
Coal 4	60	59	37	34
Coal 6	0	0	0	0
CCGT	6	4	33	30
Nuclear	6	6	0	1
PFBC	2	0	0	0
IGCC	0	0	0	0
BIGCC	0	0	0	0
Solar	-	0	-	0
Wind	-	500	-	500
Microhydro	-	500	-	500
Hibra	2	2	2	2
K.Wangtoo	4	4	4	4
Palamaneri	4	4	4	4
Budhil	2	2	2	2
L.Nagpal	2	2	2	2
Kuther	2	2	2	2
A.Duhangan	2	2	2	2
Uhl st. III	2	2	2	2
M.Bali	4	4	4	4
T. Vishnugadh	3	3	3	3
Parbati III	3	3	3	3
Dhauliganga II	3	3	3	3
Kishanganga	3	3	3	3
Kotlibhel	4	4	4	4

Uri II	4	4	4	4
Bursar	4	4	4	4
S.Kandi	1	1	1	1
Sewa st II	2	2	2	2
Pakhaldul	4	4	4	4
Kishau	5	5	5	5
Parbati I	3	3	3	3

- **Capacity utilization of the system**

Table 3.7 shows capacity utilization of the system for each planning year and also the average for all the cases. Average capacity utilization increases with the introduction of the DPG for both the TRP and IRP cases. Average capacity utilization for the TRP case is more than the respective IRP case.

Table 3.7: Capacity utilization of the system

Year	Generation Expansion Planning Cases			
	TRP without DPG	TRP with DPG	IRP without DPG	IRP with DPG
2003	57.67	57.59	57.01	56.92
2004	56.65	56.57	55.53	55.45
2005	57.45	57.83	55.87	56.24
2006	57.73	58.09	56.36	56.72
2007	58.28	57.68	56.76	57.16
2008	58.18	58.24	55.93	56.30
2009	58.48	57.60	55.77	55.83
2010	58.40	58.12	55.27	55.40
2011	58.47	57.65	54.75	54.71
2012	58.58	57.98	54.03	54.13
2013	58.23	57.87	53.65	53.51
2014	58.33	58.04	53.34	53.08
2015	58.30	58.26	52.93	52.70

2016	58.31	57.96	52.35	52.17
2017	58.24	58.17	51.75	51.58
Average	58.17	58.83	54.45	55.48

- **Reliability of electricity generation system**

Table 3.8 exhibits relative comparison of reliability expressed in terms of unserved energy in MWh of electricity generation system each year and average for all the considered cases. Average unserved energy increases with the introduction of DPG for both the TRP and IRP cases. Also average unserved energy for the TRP case is less than the corresponding IRP case.

Table 3.8: Reliability of the system

Year	Unserved Energy (MWh)			
	TRP without DPG	TRP with DPG	IRP without DPG	IRP with DPG
2003	69.538	298.658	100518	411.253
2004	1.130	6.604	1.570	9.181
2005	1.933	32.160	4.544	67.518
2006	1.410	22.871	5.919	83.078
2007	1.286	9.665	0.767	27.609
2008	6.934	82.158	0.813	29.939
2009	2.523	16.059	6.003	150.982
2010	0623	10.519	3.434	104.381
2011	0.067	1.002	1.364	47.866
2012	0.111	3.330	0.520	23.858
2013	0.051	1.582	3.917	108.834
2014	0.066	2.340	6.073	181.836
2015	0.013	1.107	0.244	15.862
2016	0.023	1.744	0.006	1.130
2017	0.003	0.415	0.046	5.080
Average	3.655	22.872	6.835	77.762

3.4.2 Cost and Pricing Implications

➢ **Total expansion cost**

Table 3.9 shows comparison of discounted expansion cost for all the cases in the planning horizon at base year of 1998. It can be observed that the total expansion cost with DPG has decreased as compared to the base case for both the TRP and IRP cases. Capital cost, fixed O&M and fuel cost decreases with the introduction of DPG plants for all the considered cases except increase in fixed O&M cost in the case of TRP. Figure 3.3 shows comparison between total expansion costs for all the considered cases.

Figure 3.3: Expansion costs for DPG

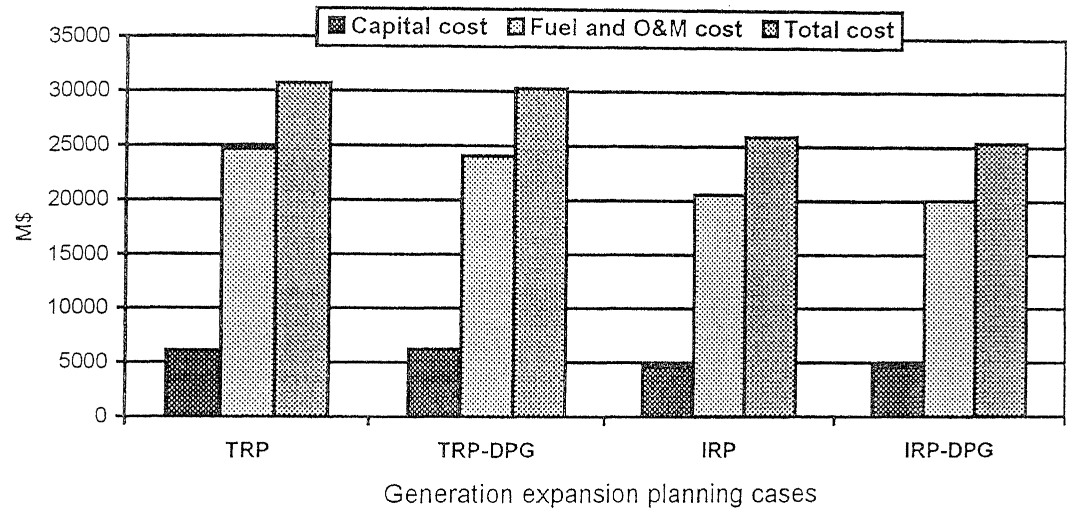


Table 3.9: Expansion costs during planning horizon

Expansion costs during planning horizon (M$)	Generation expansion planning cases			
	TRP without DPG	TRP with DPG	IRP without DPG	IRP with DPG
Capital cost (1)	6105.28	6224.94	4606.5	4614.44
Fixed O&M (2)	5242.6	5256.67	4928.85	4920.23
Fuel and Variable (3)	19410.67	18770.97	15634.67	15126.46
Fuel and O&M (2+3)	24653.27	24027.64	20563.52	20046.69
DSM cost (4)	0	0	707.5	707.5
Total Cost (1+2+3+4)	30758.55	30252.58	25877.56	25368.63

- **Electricity prices**

Electricity price for all the considered cases are shown in Table 3.10. It shows that electricity price is highest for the TRP case without DPG. With the introduction of DPG, electricity price reduces in both the TRP and IRP cases.

Table 3.10: Electricity price for expansion planning cases

Electricity price (US cents/kWh)	Generation expansion planning cases			
	TRP without DPG	TRP with DPG	IRP without DPG	IRP with DPG
Without DSM	2.52	2.49	2.23	2.17
With DSM	2.52	2.49	2.44	2.38

3.4.3 Environmental Implications

Table 3.11 shows the total CO_2, SO_2 and NO_x emission for all the considered cases in the planning horizon. From this table, it can be observed that introduction of DPG reduces GHG (only CO_2) and other pollutants' emission as well for both the TRP and IRP cases. There is a total reduction of 75.7 Gkg of CO_2 in TRP case and 99 Gkg of CO_2 in IRP case.

Table 3.11: Total environmental emissions

Emission	Generation expansion planning cases			
	TRP without DPG	TRP with DPG	IRP without DPG	IRP with DPG
CO_2 (Gkg)	2852.4	2776.7	2279.3	2180.3
SO_2 (Mkg)	17308.43	17024.7	14087.7	13537.55
NO_x (Mkg)	7874.32	7701.94	6393.1	6151.3

3.4.4 Sensitivity Analyses

➤ **Change in unit size:**

Tables 3.12 and 3.13 show effect of changing unit size of DPG on capacity mix for the TRP and IRP cases, respectively. In the base case, the candidate DPG are of 2 MW size. In the sensitivity analyses, their size is changed to 0.5 MW, 1 MW and 4 MW. As shown in these tables, changing the unit size of DPG plants do not have any significant effect on capacity mix of the considered plants. In fact, it does not change the capacity mix by any amount for the IRP case. For TRP case, the hydrothermal mix is decreasing with the change in unit size.

Table 3.12: Effect of change in unit size of DPG on capacity mix for the TRP cases

	0.5		1.0		2.0		4.0	
	2003	2017	2003	2017	2003	2017	2003	2017
Hydro	36.6	30.9	36.6	30.9	36.6	31.3	36.6	31.3
Coal	41.3	54.3	41.3	54.4	41.3	53.9	41.3	54.5
CCGT	16.4	6.7	16.4	6.7	16.4	6.7	16.4	6.7
Nuclear	3.2	4.8	3.2	4.8	3.2	4.8	3.2	4.2
Lignite	0.7	0.5	0.7	0.5	0.7	0.5	0.7	0.5
PFBC	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.6	1.2	0.6	1.2	0.6	1.2	0.6	1.2
BIGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Hydro	0.3	1.2	0.3	1.0	0.3	1.2	0.3	1.2
Total Capacity (GW)	33.37	84.26	33.37	84.35	33.4	84.2	33.37	84.21

Table 3.13: Effect of change in unit size of DPG on capacity mix for the IRP cases

	0.5		1.0		2.0		4.0	
	2003	2017	2003	2017	2003	2017	2003	2017
Hydro	37.2	34.8	37.2	34.8	37.2	34.8	37.2	34.8

Coal	42.0	43.4	42.0	43.4	42.0	43.4	42.0	43.4
CCGT	15.1	16.1	15.1	16.1	15.1	16.1	15.1	16.1
Nuclear	3.2	2.1	3.2	2.1	3.2	2.1	3.2	2.1
Lignite	0.7	0.6	0.7	0.6	0.7	0.6	0.7	0.6
PFBC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.6	1.3	0.6	1.3	0.6	1.3	0.6	1.3
BIGCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Hydro	0.3	1.3	0.3	1.3	0.3	1.3	0.3	1.3
Total Capacity (GW)	32.87	75.71	32.87	75.71	32.9	75.7	32.87	75.71

As shown in Table 3.14 the average unsereved energy and average capacity utilization do not follow any specific trend by changing the unit size of DPG plants. Average unserved energy is minimum for the case in which unit size is taken to be of 0.5 MW and the capacity utilization is highest in case of 4.0 MW unit size for TRP case. For IRP case, it does not vary much. Hence, it can be concluded that for TRP case, the smaller units of DPG increases the reliability of system whereas, larger units increases its capacity factor.

Table 3.14: Effect of change in unit size of DPG on av. unserved energy and av. capacity utilization of the system

Unit size	Av. Unserved Energy (MWh)		Av. Capacity utilization (%)	
	TRP	IRP	TRP	IRP
0.5	21.435	70.677	58.88	55.47
1.0	24.013	76.440	58.99	55.52
2.0	22.872	77.762	58.83	55.48
4.0	23.682	73.985	59.12	55.48

Table 3.15 shows the effect of changing the unit size of DPG on expansion cost. Capital cost decreases with the change in unit size, it is maximum for base case and minimum for

unit size of 4.0 MW (TRP case) and for 1.0 MW (IRP case). The total expansion cost is minimum for 4.0 MW unit size for TRP case whereas for IRP case, it is minimum for the base case itself. So, while selecting DPG plants, a thorough optimization study must be done before fixing their size as expansion cost is an important factor in power system planning.

Table 3.15: Effect of change in unit size of DPG on expansion costs

Cases	Unit size	Capital cost (M$)	Fuel and O&M (M$)	Total cost including DSM cost (M$)
TRP	0.5	6141.82	24108.17	30249.99
	1.0	6113.70	24120.15	30233.86
	2.0	6224.94	24027.64	30252.58
	4.0	6016.47	24210.32	30226.79
IRP	0.5	4596.62	20078.10	25382.22
	1.0	4566.66	20091.09	22507.20
	2.0	4614.44	20046.69	25368.63
	4.0	4609.65	20052.19	25369.35

Table 3.16 shows effect of change in unit size on environmental emissions. Changing unit size of DPG plants has negative impact on emissions of green house gas and other pollutants in TRP case as it is minimum for the base case but in IRP case, the emissions are minimum for smallest unit size i.e. for 0.5 MW case. Even though, the emissions are minimum for 0.5 MW case, the difference is not significant and it can be weighed down when other factors like expansion costs etc. are taken into consideration. However, for the TRP case, the difference is significant. Thus, it can be concluded that the size of DPG plant can only be fixed after exploring all the cases and perspectives and also it very much depends upon the main aim which is to be achieved like reducing the total cost or reducing the total emissions etc.

Table 3.16: Effect of change in unit size of DPG on environmental emission

Emission	Unit size (MW)			
	0.5	1.0	2.0	4.0

TRP	CO_2 (Gkg)	2804.18	2789.35	2776.7	2819.30
	SO_2 (Mkg)	17180.37	17059.6	17024.7	17232.50
	NO_x (Mkg)	7767.44	7736.50	7701.94	7811.92
IRP	CO_2 (Gkg)	2175.57	2179.97	2180.3	2178.47
	SO_2 (Mkg)	13489.40	13523.35	13537.55	13521.97
	NO_x (Mkg)	6148.26	6159.17	6151.3	6149.28

- **Change in capacity cost:**

- **Solar**

Since solar DPG plants were not selected in any of the considered cases, sensitivity analyses were carried out with respect to the capacity cost of solar DPG plants by changing the capacity cost from 3 $/W$_P$ to 2.5, 2,1.5, 1.0, 0.5 $/W$_P$. It was found that even at the capacity cost of 1.0 $/W$_P$, solar plants were not found cost effective. It was selected at the unit cost of 0.5 $/W$_P$ for both the TRP and the IRP cases but even in that case they are not fully selected.

- **Wind**

Since all available wind power plants got selected, the capacity cost of wind power plants were varied from 700 $/kW to 1000, 1500, 1800, 2000, 2500, 3000, 3500, 4000, 4500, 5000, 5500, 6000, 6500, 7000, 7500, 8000, 8500, 9000, 9500 $/kW. Results show that the few units of wind power plants would be selected up to the cost of 6000 $/kW for the IRP case and up to the cost of 2000 $/kW for the TRP case. These plants were not selected at the capacity cost of 6500 $/kW for the IRP case and at 3000 $/kW for the TRP case.

- **Micro-hydro**

Since almost all micro-hydro units were selected for the considered cases, the capacity cost of micro-hydro was varied by +20%, +50%, +80%, +120%, +150% of base case value. These were found cost effective even when the unit capacity cost was increased by 120% for the TRP case and 150% for the IRP case but at these capacity costs only 9 plants were selected out of 500 candidate plants.

CCGT	7.1	7.0	6.8	6.7
Nuclear	4.8	4.8	4.2	4.8
Lignite	0.5	0.5	0.5	0.5
PFBC	1.1	1.1	0.5	0.5
IGCC	0.0	0.5	0.5	0.0
BIGCC	0.2	0.0	0.0	0.0
Solar	-	0.0	-	-
Wind	-	-	1.2	-
Micro Hydro	-	-	-	1.2
Total Capacity (GW)	84.0	84.14	84.06	84.16

Table 3.18: Capacity mix (%) for IRP cases

	Base case	Solar DPG	Wind DPG	Micro-hydro DPG
Hydro	34.8	34.9	34.7	34.8
Coal	45.4	45.6	44.6	44.1
CCGT	16.7	17.1	17.0	16.7
Nuclear	2.1	1.4	1.4	2.1
Lignite	0.6	0.6	0.6	0.6
PFBC	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0
BIGCC	0.0	0.0	0.0	0.0
Solar	-	0.0	-	-
Wind	-	-	1.3	-
Micro Hydro	-	-	-	1.3
Total Capacity (GW)	75.71	75.46	75.96	75.71

- **Generation mix:**

Table 3.19 and 3.20 show the generation mix during the planning horizon for both the TRP and IRP cases, respectively. For the TRP case, the generation share of costly plants, like CCGT, nuclear and PFBC plants are lowest in case of wind DPG. Share of coal in this case also is less than the base case. Total generation is minimum for wind DPG case. The generation avoided is 1050 GWh from the base case. It is a considerable saving given only 1% generation share of the wind DPG. This saving is due to the elimination of T&D losses. For IRP case, the share of nuclear generation is lowest in case of wind DPG. The share of coal generation is minimum for micro-hydro DPG case and it is next minimum for wind DPG case. PFBC, IGCC and BIGCC plants are not contributing towards generation under IRP perspective. The maximum avoided generation is in case of wind DPG and it is equal to about 1040 GWh.

Table 3.19: Generation mix (%) for TRP cases

	Base case	Solar DPG	Wind DPG	Micro-hydro DPG
Hydro	22.6	22.5	22.6	22.6
Coal	66.0	65.5	65.8	66.2
CCGT	3.7	3.7	3.6	3.6
Nuclear	5.1	5.1	4.5	5.1
Lignite	0.6	0.6	0.6	0.6
PFBC	1.6	1.6	0.8	0.8
IGCC	0.0	0.7	0.7	0.0
BIGCC	0.0	0.0	0.0	0.0
Solar	-	0.0	-	-
Wind	-	-	1.0	-
Micro Hydro	-	-	-	0.8
Total Generation (TWh)	429.94	429.94	428.89	429.11

Table 3.20: Generation mix (%) for IRP cases

	Base case	Solar DPG	Wind DPG	Micro-hydro DPG
Hydro	30.1	30.1	30.2	30.2
Coal	55.2	55.7	54.3	54.0
CCGT	11.0	11.2	11.2	11.0
Nuclear	2.6	1.8	1.8	2.6
Lignite	0.9	0.9	0.9	0.9
PFBC	0.0	0.0	0.0	0.0
IGCC	0.0	0.0	0.0	0.0
BIGCC	0.0	0.0	0.0	0.0
Solar	-	0.0	-	-
Wind	-	-	1.3	-
Micro Hydro	-	-	-	1.0
Total Generation (TWh)	322.14	322.14	321.1	321.32

- **Average capacity utilization and average unserved energy:**

From Table 3.21, it is observed that the capacity utilization of the system is highest for wind DPG case under both TRP and IRP scenario. However, the unserved energy is also highest for the same. Therefore, the system reliability deteriorates in this case. System is found to be most reliable under the base case for TRP perspective and under the case of solar DPG for IRP perspective.

Table 3.21: Av. Capacity Utilization & Av. Unserved Energy

		Base case	Solar DPG	Wind DPG	Microhydro DPG
TRP	Av. Capacity Utilization	58.20	58.15	58.75	58.34
	Av. Unserved Energy	8.152	8.262	17.029	15.226
IRP	Av. Capacity Utilization	54.52	54.54	55.12	54.84
	Av. Unserved Energy	17.725	16.050	40.519	27.543

- **Cost and pricing implications:**

Table 3.22 shows the cost-effectiveness of each of the DPG plants for both the TRP and IRP cases. All the costs are minimum for wind DPG case. Hence, wind plant is most cost-effective. When compared to the base case, the saving in total cost is considerable for the wind DPG case. For TRP case, the saving is 410.74 M$ and for IRP case, it is 387.34 M$.

Table 3.22: Effect of different DPGs on Expansion Costs

Expansion costs during planning horizon (M$)		Generation expansion planning cases			
		Base case	Solar DPG	Wind DPG	Microhydro DPG
TRP	Capital cost	6110.42	6153.2	6072.6	6277.0
	Fuel and O&M	24644.0	24598.3	24271.0	24287.23
	DSM cost	0.0	0.0	0.0	0.0
	Total Cost	30754.44	30751.5	30343.7	30564.2
IRP	Capital cost	4617.12	4575.87	4546.6	4650.1
	Fuel and O&M	20534.2	20581.1	20217.4	20397.5
	DSM cost	707.5	707.5	707.5	707.5
	Total Cost	25858.84	25864.5	25471.5	25755.1

- **Environmental implications:**

Table 3.23 shows the environmental implication of each of the DPG plants for TRP and IRP cases. Emission of greenhouse gas (in this study only CO_2) is minimum in case of micro-hydro DPG for both the cases and it is next minimum for wind DPG case. It is highest in base case for the TRP case and in case of solar DPG for the IRP case. The emissions of other pollutants SO_2 and NO_X are also minimal for micro-hydro case except in case of SO_2 emission for TRP case where it is minimum for wind DPG case. The reduction of emission of GHG in micro-hydro DPG case from the base case is 32.4 Gkg for TRP case and 23.55 Gkg for IRP case. Hence, from the environmental point of view, micro-hydro DPG case has got the highest mitigating potential.

Table 3.23: Effect of different DPGs Environmental Emissions

Environmental emissions		Generation expansion planning cases			
		Base case	Solar DPG	Wind DPG	Micro hydro DPG
TRP	CO_2 (Gkg)	2854.6	2848.88	2831.7	2822.2
	SO_2 (Mkg)	17346.3	17256.9	17207.7	17259.8
	NO_x (Mkg)	7878.1	7840.6	7796.0	7801.74
IRP	CO_2 (Gkg)	2252.09	2278.7	2233.52	2228.54
	SO_2 (Mkg)	13918.8	14077.1	13845.13	13793.7
	NO_x (Mkg)	6329.85	6393.87	6279.9	6273.7

3.5 CONCLUSIONS

This work has studied the impact of considering DPG in the generation expansion planning on the expansion cost, emission of GHG and other pollutants. Studies were carried out for both the Traditional Resource Planning (TRP) and Integrated Resource Planning (IRP) cases for the NREB system of India. On the basis of the results obtained for various cases and sensitivity analyses done, following conclusions can be drawn.

- With the introduction of DPG plants, hydrothermal mix increases for both the TRP and the IRP cases. Capacity mix of coal and CCGT decreases and that of nuclear increases for both the TRP and IRP cases. Solar plants were not selected in any of the cases, while all available wind and micro-hydro units got selected in both the TRP and IRP cases. Total installed capacity increases slightly with the introduction of DPG but the total energy generation has reduced considerably. Total generation avoided is 1.9 TWh over the base case in both TRP and IRP cases. Average capacity utilization increases and the average unserved energy increases with the introduction of the DPG for both the TRP and IRP cases. The reliability of the system deteriorates with the introduction of DPG.
- There is a major reduction in the total expansion cost with the introduction of DPG and it reduces electricity price.
- Introduction of DPG reduces GHG emissions and other pollutants' emissions also.

- Changing unit size of DPGs does not show any specific trend on the utility planning parameters, environmental emissions and expansion cost. But while selecting DPG among different available options, their unit size can be fixed depending on the purpose to be achieved.
- Solar plants are not selected in any of the cases due to their higher capacity cost. Reducing the capacity cost of solar make them selected at the cost of 0.5 $/W_P$ for both the TRP and IRP cases.
- All available units of wind DPG got selected for both the TRP and IRP cases. When the capacity cost of wind units are increased to 3000 $/kW for the TRP case and to 6500 $/kW for the IRP case, they do not get selected.
- All units of micro-hydro DPG are selected fully in both TRP and IRP case. They are not selected when their capacity cost is increased by 120% of base value for TRP case and 150% of base value for IRP case.
- From the study of individual DPG plants, the wind DPG plant has been found to be most cost-effective and micro-hydro DPG plants with highest GHG mitigation potential. The wind DPG plants are found to have next highest mitigating potential. With wind DPG plants, a reduction is observed in total generation for both TRP and IRP case. The capacity utilization also improves. However, the reliability of the system deteriorates.

CHAPTER 4

CONCLUSIONS

Increased emission of greenhouse gases and other pollutants from power sector and its detrimental impacts on the global and local environment has made this aspect to be addressed in the utility planning. In developing countries of Asia, including India, power sector is at a stage of complete restructuring and reformation by paving in a way to corporatization and privatization of the whole power sector and shifting the power generation from conventional fuel based, remotely located, large utilities to renewable based, small plants closely located to the consumers on the distribution side. During this time of transition, it is critical to determine how best to take advantage of the opportunities it presents to protect the environment and avert threats to public health and accordingly plan expansion of the power sector. In this work, cost-effectiveness and environmental emission mitigating potential of independent power producers (IPPs) and distributed power generation (DPGs) has been studied and their impact on the power sector planning has been analyzed. The study has been carried out under the traditional resource planning (TRP) and integrated resource planning (IRP) perspectives on Northern Regional Electricity Board network of India. The main findings of the study carried out in this thesis are given in following paragraph.

The introduction of IPPs decreases the total capacity mix for both TRP and IRP perspectives. The average unserved energy decreases while average capacity factor increases. It reduces the emissions of greenhouse gases and other pollutants and at the same time, decreases the total expansion cost also. The optimum value of plant availability factor (PAF) of IPPs is found to be 0.7 from the cost point of view. In this study, the base value of PAF is taken as 0.675 as per the CEA norms. However, an increase in PAF increases the environmental emissions. Increase in power purchase from IPPs has pronounced impact on the environmental emission reduction. An increase in the power purchase from IPPs avoids the capacity addition to the system and hence decreases the total capacity cost and environmental emissions.

With the introduction of DPGs, the generation avoided is 1900 GWh of energy for both the TRP and IRP perspectives in the NREB system. Average capacity utilization and average unserved energy increases for the DPG case. Total expansion cost and the environmental emission decreases. Solar DPG plants are not selected in any of the case because of their high capital cost. Wind and micro hydro DPG plants are found to be cost-effective and are fully selected in all the cases. From the analysis of individual DPG plant, it was found that wind DPG plant is the most cost-effective and micro hydro DPG plant has the highest environmental emission mitigating potential.

As a consequence of the study carried out in this thesis, following areas of further research work have been identified:

1. While identifying the environmental emission mitigation potential in the planning studies, cost of societal benefits due to the emission reduction have not been considered in the model. The IRPA can be modified to include societal benefit also.
2. In some of the countries carbon tax has been introduced to mitigate the greenhouse gas emission. This aspect may also be studied on Indian power system networks.
3. In this study, the candidate IPP was a fossil fuel based plant. Further research can be done with renewable energy sources based and clean coal technologies plant considered as IPPs.

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Appendix A

MATHEMATICAL FORMULATION

The formulation of the conventional generation expansion planning is based on the least cost optimization criteria as described below.

➢ Objective function

The least cost generation expansion planning minimizes the total cost of candidate power plants and the cost of power generation from existing and candidate power plants over the complete planning horizon. Let, the total planning horizon is for T years, each year having 's' seasons, each season divided into 'P' blocks, each block divided into 't' vintages, J being the total number of candidate power plants and K being the total number of existing power plants.

Mathematically, the least cost generation expansion plan has objective to,

$$\text{Minimize } \sum_{j=1}^{J}\sum_{v=1}^{T}\left(C_{jv} - W_{jv}\right)\times Y_{jv} +$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\sum_{j=1}^{J} U_{jpstv}\times F_{jpstv}\times N_{st}\times\theta_{pst} +$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\sum_{k=1}^{K} U_{kpstv}\times F_{kpstv}\times N_{st}\times\theta_{pst} \qquad (2.1).$$

Where,

C_{jv}: Discounted capital cost of candidate power plant j, to be commissioned in vintage v.

W_{jv}: Discounted salvage value of power plant j, commissioned in year v after time

horizon T.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

YP_{mv}: Number of pump storage hydro plants type m installed in year v (An integer variable).

N_{st}: Number of days in season s of year t.

θ_{pst}: Width of block p of chronological load curve of season s of year t.

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

F_{jpstv}: Cost of per unit power generation from candidate power plant j of vintage v in block p of season s in year t.

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

F_{kpstv}: Cost of per unit power generation from existing or committed power plant k of vintage v in block p of season s in year t.

➢ Constraints

The above least cost optimization is subject to the following system constraints.

a) Demand constraints

This constraint states that the total power generation in each block of the planning horizon, from candidate and existing plants, will be more than or equal to the power demand during that period. It can be mathematically written as

$$\sum_{v=1}^{t}\sum_{j=1}^{J} U_{jpstv} \times \left(1 - M_{jpst}\right) + \sum_{v=-V}^{t}\sum_{k=1}^{K} U_{kpstv} \times \left(1 - M_{kpst}\right) \geq Q_{pst} \qquad (2.2).$$

for all p, s, t.

Where,

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

M_{jpst}: Transmission loss for transmitting power from candidate generating station j to load center in block p of season s in year t.

U_{kpstv}: Power generation from existing plant k of vintage v in block p of season s in year t.

M_{kpst}: Transmission loss for transmitting power from existing generating station k to load center in block p of season s in year t.

b) Reliability constraints

This constraint imposes the condition that the power demand from all the plants (the candidate and the existing plants of all the types) must be greater than or equal to the sum of the power demand by the consumers and the reserve margin.

$$\sum_{k=1}^{K} \sum_{v=V}^{t} B_{kv} \times \left(1 - M_{kp^*st}\right) + \sum_{j=1}^{J} \sum_{v=1}^{t} Y_{jv} \times B_{jv} \times \left(1 - M_{jp^*st}\right) \geq Q_{p^*st}\left(1 + rm\right) \qquad (2.3).$$

for all t, s.

(P^* represents the peak block).

Where,

B_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

M_{kp^*st}: Transmission loss for transmitting power from generating station k to load center in block p of season s in year t.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

B_{jv}. Maximum capacity of candidate power plant j of vintage v.

M_{jp^*st}: Transmission loss for transmitting power from candidate generating station j to load center in block p of season s in year t.

Q_{p^*st}: Power demand in block p of season s in year t.

rm: Reserve margin.

c) Guarantee condition for energy supply for mixed hydro thermal system

This constraint states that the energy available from all the plants must be greater than or equal to the energy demand during all time interval and seasons.

$$\sum_{\substack{k=1 \\ k \neq \text{hydro}}}^{K} \sum_{v=-V}^{t} \sum_{p=1}^{P} a_{kv} \times B_{kv} \times Y_{kv} \times \theta_{pst} + \sum_{\substack{j=1 \\ j \neq \text{hydro}}}^{J} \sum_{v=1}^{t} \sum_{p=1}^{P} a_{jv} \times B_{jv} \times Y_{jv} \times \theta_{pst} +$$

$$\sum_{k=1}^{K}\sum_{v=-V}^{t}\sum_{p=1}^{P}\beta_{kv}\times U_{kpstv}\times\theta_{pst}+\sum_{j=1}^{J}\sum_{v=1}^{t}\sum_{p=1}^{P}\beta_{jv}\times U_{jpstv}\times\theta_{pst}\geq\sum_{P=1}^{p}Q_{pst}\times\theta_{pst} \qquad (2.4).$$

k=hydro j=hydro

for all t, s

Where,

a_{kv}: Availability of existing or committed power plant k of vintage v.

B_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

Y_{kv}: Number of power plant of type k installed in year v (an integer variable).

θ_{pst}: Width of block p of chronological load curve of season s in year t.

a_{jv}: Availability of candidate power plant j of vintage v.

B_{jv}. Maximum capacity of candidate power plant j of vintage v.

Y_{jv}: Number of power plant of type j installed in year v (An integer variable).

β_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

U_{kpstv}: Power generation form plant k of vintage v in block p of season s in year.

β_{jv}: Firm factor of hydro plant j of vintage v.

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

Q_{pst}: Power demand in block p of season s in year t.

d) Plant availability constraints

This constraint defines the maximum available generation from each power plant depending on their availability factor.

$$U_{jpstv}\leq Y_{jv}\times a_{jv}\times B_{jv}$$

for all j, v, p, s, t.

and

$$U_{kpstv}\leq a_{jv}\times B_{kv}$$

for all k, v, p, s, t (2.5).

Where,

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in

year t.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

a_{jv}: Availability of candidate power plant j of vintage v.

B_{jv}: Maximum capacity of candidate power plant j of vintage v.

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

a_{kv}: availability of existing or committed power plant k of vintage v.

B_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

e) Annual energy constraints

This constraint defines the maximum energy, which can be generated from each plant considering their maintenance period.

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{jpstv} \times \theta_{pst} \times N_{st} \leq (8760 - m_{jv}) \times B_{jv} \times Y_{jv}$$

for all j, v, t.

and

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{kpstv} \times \theta_{pst} \times N_{st} \leq (8760 - m_{kv}) \times B_{kv}$$

for all k, v, t (2.6).

Where,

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

θ_{pst}: Width of block p of chronological load curve of season s of year t.

N_{st}: Number of days in season s of year t

m_{jv}: Schedule maintenance hours per year of candidate power plant j of vintage v.

B_{jv}: Maximum capacity of candidate power plant j of vintage v.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

m_{kv}: Schedule maintenance hours per year of existing or committed plant k of vintage v.

B_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

f) Hydro energy availability constraints

This constraint defines the limit on total hydro energy generation available from each hydro plant, during each period.

$$\sum_{p=1}^{P}\left(U_{jpstv} \times \theta_{pst}\right) \times N_{st} \leq \pi_{jstv}$$

for all j, s, t, v (j=Hydro plants).

and

$$\sum_{p=1}^{P}\left(U_{kpstv} \times \theta_{pst}\right) \times N_{st} \leq \pi_{kstv}$$

for all k, s, t, v (k=Hydro plants) (2.7).

Where,

U_{jpstv} : Power generation from candidate plant j of vintage v in block p of season s in year t.

θ_{pst} : Width of block p of chronological load curve of season s of year t.

N_{st}: Number of days in season s of year t.

π_{jstv} : Hydro energy available at hydro plant j of vintage v, in season s, in year t.

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

π_{kstv} : Hydro energy available at hydro plant k of vintage v, in season s, in year t.

g) Maximum potential capacity constraints

This constraint imposes the limit on the number of power plants of any type installed in any year.

$$\sum_{v=1}^{T} Y_{jv} \leq \alpha_j$$

for all j (2.8).

where,

Y_{jv} : Number of power plants of type j installed in year v (An integer variable).

α_j: Maximum number of units of power plant type j.

h) Fuel or resource availability constraints

This constraint imposes the maximum limit on energy generation for each type computed from the availability of fuel resources

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t} Y_{kv} \times U_{kpstv} \times \theta_{pst} \times N_{st} + \sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t} Y_{jv} \times U_{jpstv} \times \theta_{pst} \times N_{st} \le X_{j\max}$$

for all k, j   k and j are some type of plants   (2.9).

Where,

Y_{kv}: Number of power plants of type k installed in year v (An integer variable).

U_{kpstv} : Power generation from plant k of vintage v in block p of season s in year t.

θ_{pst} : Width of block p of chronological load curve of season s of year t.

N_{st} : Number of days in season s of year t.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

$X_{j\max}$: Maximum energy resource available for plant type j (computed based on the maximum fuel resource availability).

Appendix B

B-1: Existing thermal power plants

NAME	Fuel type	Fuel con.	Cal. Value (kBtu/kg)	CO_2 emis. (kg/MWh)	SO_2 emis. (kg/MWh)	NO_x emis. (kg/MWh)	Capacity (MW)	Heat rate (kcal/kwh)	Oper. cost (000'$/MWh)	Annual maint. (Hours)	Fixed O&M (000'$/MWmonth)
BADARPUR1	COAL	0.8	14.27	1144	8	5.14	85	3213	0.0012	864	2
BADARPUR2	COAL	0.8	14.27	1144	8	5.14	85	3213	0.0012	864	2
BADARPUR3	COAL	0.8	14.27	1144	8	5.14	85	3213	0.0012	864	2
BADARPURXT-1	COAL	0.7	14.27	1001	7	4.45	190	2781	0.0012	864	2
BADARPURXT-2	COAL	0.7	14.27	1001	7	2.78	190	2781	0.0012	864	2
IP-60	COAL	0.85	15.19	1277.83	8.5	5.82	54	3636	0.0012	864	2
IP-1	COAL	0.85	15.19	1277.83	8.5	5.82	56	3636	0.0012	864	2
IP-2	COAL	0.85	15.19	1277.83	8.5	5.82	56	3636	0.0012	864	2
IP-3	COAL	0.85	15.19	1277.83	8.5	5.82	56	3636	0.0012	864	2
RAJGHAT-2	COAL	0.82	17.65	1473.27	8.2	6.52	61	4075	0.0012	864	2
RAJGHAT-3	COAL	0.82	17.65	1473.27	8.2	6.52	60	4075	0.0012	864	2
GAS-DESU-1WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-2WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-3WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-4WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-5WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-6WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
FARIDABADXT1	COAL	0.9	17.88	1617	9	7.25	49	4530	0.0012	864	2
FARIDABADXT2	COAL	0.9	17.88	1617	9	7.25	49	4530	0.0012	864	2
FARIDABADXT3	COAL	0.9	17.88	1617	9	7.25	49	4530	0.0012	864	2
PANIPAT-1	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-2	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-3	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-4	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-5	COAL	0.85	15.34	1277.83	8.5	3.63	190	3630	0.0012	864	2
FARIDABADCCGT-A	GAS	0.221	41.74	504.43	0.37	1.59	139	1982	0.0008	1296	1.67
PAMPORE-1GT	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-2GT	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-3GT	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-4GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-5GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-6GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-7GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
BHATINDAlehmoh1	COAL	0.75	15.82	1155	7.5	3.3	190	3303	0.0012	864	2
BHATINDAlehmoh2	COAL	0.75	15.82	1155	7.5	3.3	190	3303	0.0012	864	2
GNDTP-1	COAL	0.75	15.82	1155	7.5	3.34	98	3340	0.0012	864	2
GNDTP-2	COAL	0.75	15.46	1155	7.5	3.27	98	3265	0.0012	864	2
GNDTP-3	COAL	0.75	15.46	1155	7.5	3.27	98	3265	0.0012	864	2
GNDTP-4	COAL	0.75	15.46	1155	7.5	3.27	98	3265	0.0012	864	2
ROPAR-I/1	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-I/2	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-II/1	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-II/2	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-IIIXT-1	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-IIIXT-2	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
KOTA-1	COAL	0.7	16.27	1103.67	7	3.21	98	3207	0.0012	864	2
KOTA-2	COAL	0.7	16.27	1103.67	7	3.21	98	3207	0.0012	864	2
KOTAXT-3	COAL	0.64	16.27	1009.07	6.4	2.9	190	2899	0.0012	864	2
KOTAXT-4	COAL	0.64	16.27	1009.07	6.4	2.9	190	2899	0.0012	864	2
KOTAXT-5	COAL	0.64	16.27	1009.07	6.4	2.9	190	2899	0.0012	864	2
SURATGARHTPS-I 1	COAL	0.46	16.27	725.27	4.6	2.08	226	2084	0.0012	864	2
ANTAGAS-1	GAS	0.221	41.74	504.43	0.37	1.59	85	1982	0.0008	1296	1.67
ANTAGAS-2	GAS	0.221	41.74	504.43	0.37	1.59	85	1982	0.0008	1296	1.67
ANTAGAS-3	GAS	0.221	41.74	504.43	0.37	1.59	85	1982	0.0008	1296	1.67

ANTAGAS-4	GAS	0.221	41.74	504.43	0.37	1.59	145	1982	0.0008	1296	1.67
RAMGARHGAS	GAS	0.221	41.74	504.43	0.37	1.55	3	1942	0.0008	1296	1.67
RAMGARHGAS	GAS	0.221	41.74	504.43	0.37	1.55	35	1942	0.0008	1296	1.67
RAPP-1	NUCL	0.027	406350	0	0	0	90	3072	0.0015	864	2.7
RAPP-2	NUCL	0.027	406350	0	0	0	180	3072	0.0015	864	2.7
ANPARA'A'-1	COAL	0.75	16.08	1155	7.5	3.36	190	3357	0.0012	864	2
ANPARA'A'-2	COAL	0.75	16.08	1155	7.5	3.36	190	3357	0.0012	864	2
ANPARA'A'-3	COAL	0.75	16.08	1155	7.5	3.36	190	3357	0.0012	864	2
ANPARA'B'-1	COAL	0.6	16.08	924	6	2.64	460	2642	0.0012	864	2
ANPARA'B'-2	COAL	0.6	16.08	924	6	2.64	460	2642	0.0012	864	2
H'GANJB-1	COAL	2003	17.88	1796.67	10	8.06	36	5036	0.0012	864	2
H'GANJB-3	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJB-2	COAL	2003	17.88	1796.67	10	8.06	36	5036	0.0012	864	2
H'GANJB-4	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJC-1	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJC-2	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJC-3	COAL	0.89	17.88	1599.03	8.9	7.17	94	4482	0.0012	864	2
NCR-1DADRI	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
NCR-2	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
NCR-3	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
NCR-4	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
OBRA-1	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-2	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-3	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-4	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-5	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-6	COAL	0.8	15.87	1232	8	5.72	84	3575	0.0012	864	2
OBRA-7	COAL	0.8	15.87	1232	8	5.72	84	3575	0.0012	864	2
OBRA-8	COAL	0.8	15.87	1232	8	5.72	84	3575	0.0012	864	2
OBRA-9	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-10	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-11	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-12	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-13	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
PANKI-3	COAL	0.7	17.68	1232	7	5.58	94	3485	0.0012	864	2
PANKI-4	COAL	0.7	17.68	1232	7	5.58	94	3485	0.0012	864	2
PANKI-1	COAL	2003	17.68	1760	10	7.97	29	4979	0.0012	864	2
PANKI-2	COAL	2003	17.68	1760	10	7.97	29	4979	0.0012	864	2
PARICHHA-1	COAL	0.89	12.77	1207.43	8.9	3.2	98	3200	0.0012	864	2
PARICHHA-2	COAL	0.89	12.77	1207.43	8.9	3.2	98	3200	0.0012	864	2
RIHANDSTPS-1	COAL	0.6	14.61	858	6	2.4	460	2401	0.0012	864	2
RIHANDSTPS-2	COAL	0.6	14.61	858	6	2.4	460	2401	0.0012	864	2
SINGRAULI-1	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-2	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-3	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-4	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-5	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-6	COAL	0.55	15.24	826.83	5.5	2.3	460	2296	0.0012	864	2
SINGRAULI-7	COAL	0.55	15.24	826.83	5.5	2.3	460	2296	0.0012	864	2
TANDA-1	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
TANDA-2	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
TANDA-3	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
TANDA-4	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
UNCHAHAR-3	COAL	0.7	15.08	1026.67	7	2.94	190	2939	0.0012	864	2
UNCHAHAR-1	COAL	0.7	15.08	1026.67	7	2.94	190	2939	0.0012	864	2
UNCHAHAR-2	COAL	0.7	15.08	1026.67	7	2.94	190	2939	0.0012	864	2
AURIYAGAS-1	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-2	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-3	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-4	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-5	GAS	0.221	41.74	504.43	0.37	1.59	99	1982	0.0008	1296	1.67
AURIYAGAS-6	GAS	0.221	41.74	504.43	0.37	1.59	99	1982	0.0008	1296	1.67
DADRICCGT-A-1	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-A-2	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-A-3	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-A-4	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67

DADRICCGT-B-1WH	GAS	0.221	41.74	504.43	0.37	1.59	142	1982	0.0008	1296	1.67
DADRICCGT-B-2WH	GAS	0.221	41.74	504.43	0.37	1.59	142	1982	0.0008	1296	1.67
NAPP-1	NUCL	0.027	406350	0	0	0	198	2844	0.0015	864	2
NAPP-2	NUCL	0.027	406350	0	0	0	198	2844	0.0015	864	2
PANIPAT-6	COAL	0.812	13.49	1190.93	8.12	2.76	190	2762	0.0012	864	2
FARIDABADCCGT-A	GAS	0.237	41.74	540.95	0.39	1.65	139	2062	0.0008	1296	1.67
FARIDABADCCGT-B	GAS	0.237	41.74	540.95	0.39	1.65	140	2062	0.0008	1296	1.67
SURATGARHTPS-I2	COAL	0.812	13.49	1131.39	8.12	2.76	226	2762	0.0012	864	2
BARSINGSARLIG-1	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
BARSINGSARLIG-2	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
ANTA-IICCGT-1	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
ANTA-IICCGT-2	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
ANTA-IICCGT-3	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
ANTA-IICCGT-4	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
ANTA-IICCGT-5	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
RAPP-3	NUCL	0.027	406350	0	0	0	198	2777	0.0015	864	2
RAPP-4	NUCL	0.027	406350	0	0	0	198	2777	0.0015	864	2
ANPARA'C'-1	COAL	0.719	15	1054.53	7.19	2.72	460	2717	0.0012	864	2
ANPARA'C'-2	COAL	0.719	15	1054.53	7.19	2.72	460	2717	0.0012	864	2
RIHAND-II-1	COAL	0.679	15.87	1045.66	6.79	2.72	460	2717	0.0012	864	2
RIHAND-II-2	COAL	0.679	15.87	1045.66	6.79	2.72	460	2717	0.0012	864	2
ROSA-1	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
ROSA-2	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
UNCHAHAR-4	COAL	0.691	15.87	1064.14	6.91	2.76	190	2762	0.0012	864	2
AURIYA-IICCGT-1	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
AURIYA-IICCGT-2	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
AURIYA-IICCGT-3	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
AURIYA-IICCGT-4	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
AURIYA-IICCGT-5	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
GLOBALBOARDCGT	GAS	0.237	41.74	540.95	0.39	1.65	126	2062	0.0008	1296	1.67
MAGNUMCCGT	GAS	0.237	41.74	540.95	0.39	1.65	24	2062	0.0008	1296	1.67
PHOENIXCCGT	GAS	0.237	41.74	540.95	0.39	1.65	170	2062	0.0008	1296	1.67
AURIYA-IICCGT-6	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
ANTA-IICCGT-6	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
DHOLPURCCGT	GAS	0.237	41.74	540.95	0.39	1.65	233	2062	0.0008	1296	1.67
SURATGARH-II	COAL	0.812	13.49	1131.39	8.12	2.76	226	2762	0.0012	864	2
SURATGARH-II	COAL	0.812	13.49	1131.39	8.12	2.76	226	2762	0.0012	864	2
MATHANIACCGT	GAS	0.237	41.74	540.95	0.39	1.65	34	2062	0.0008	1296	1.67
MATHANIACCGT	GAS	0.237	41.74	540.95	0.39	1.65	34	2062	0.0008	1296	1.67
MATHANIACCGT	GAS	0.237	41.74	540.95	0.39	1.65	68	2062	0.0008	1296	1.67

B-2: Existing hydro power plants

Name	Capacity (MW)	EA year	Availibility	Opearting cost (000'$/ MWh)	Fixed O&M cost (000'$/ MWmonth)	Energy - Season1 (MWh)	Energy-Season2 (MWh)
W.Y.CANAL-1	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-2	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-3	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-4	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-5	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-6	8	2003	0.87	0	1.39	11000	31000
ANDHRAU-1-3	17	2003	0.87	0	1.39	24000	33000
HPSMALL	9	2003	0.87	0	1.39	36000	57000
BAIRASIUL-1	60	2003	0.87	0	1.39	57000	190000
BAIRASIUL-2	60	2003	0.87	0	1.39	57000	191000
BAIRASIUL-3	60	2003	0.87	0	1.39	57000	190000
BANER	12	2003	0.87	0	1.39	14000	23000
THIROT	4.5	2003	0.87	0	1.39	19000	29000
GAJ	10.5	2003	0.87	0	1.39	5000	9000
BASSI-1	15	2003	0.87	0	1.39	28000	49000
BASSI-2	15	2003	0.87	0	1.39	28000	49000
BASSI-3	15	2003	0.87	0	1.39	28000	49000
BASSI-4	15	2003	0.87	0	1.39	28000	49000
BINWA	6	2003	0.87	0	1.39	14000	27000
CHAMERA-I-1	180	2003	0.87	0	1.39	314000	400000
CHAMERA-I-2	180	2003	0.87	0	1.39	314000	400000
CHAMERA-I-3	180	2003	0.87	0	1.39	315000	400000
GIRIBATA-1	30	2003	0.87	0	1.39	48000	77000
GIRIBATA-2	30	2003	0.87	0	1.39	48000	77000
SANJAYBHABA-1	40	2003	0.87	0	1.39	78000	113000
SANJAYBHABA-2	40	2003	0.87	0	1.39	78000	113000
SANJAYBHABA-3	40	2003	0.87	0	1.39	79000	113000
CHENANI	23	2003	0.87	0	1.39	30000	60000
GANDERBAL	15	2003	0.87	0	1.39	13000	26000
J&K-SMALL	6	2003	0.87	0	1.39	5000	9000
KARGIL	4	2003	0.87	0	1.39	5000	9000
LOWERJHELUM	105	2003	0.87	0	1.39	171000	362000
MOHORA	9	2003	0.87	0	1.39	26000	53000
SALAL-I-1	115	2003	0.87	0	1.39	339000	508000
SALAL-I-2	115	2003	0.87	0	1.39	339000	508000
SALAL-I-3	115	2003	0.87	0	1.39	339000	509000
SALAL-II-1	115	2003	0.87	0	1.39	142000	212000
SALAL-II-2	115	2003	0.87	0	1.39	142000	212000
SALAL-II-3	115	2003	0.87	0	1.39	142000	213000
UPPERSINDH-I	22.6	2003	0.87	0	1.39	33000	68000
URI-1	120	2003	0.87	0	1.39	175000	407000
URI-2	120	2003	0.87	0	1.39	175000	407000
URI-3	120	2003	0.87	0	1.39	5000	407000
URI-4	120	2003	0.87	0	1.39	175000	407000
ANANDPURSAHIB1	34	2003	0.87	0	1.39	61000	166000
ANANDPURSAHIB2	34	2003	0.87	0	1.39	61000	166000
ANANDPURSAHIB3	34	2003	0.87	0	1.39	61000	166000
ANANDPURSAHIB4	34	2003	0.87	0	1.39	62000	166000
BEASDEHAR-1	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-2	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-3	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-4	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-5	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-6	165	2003	0.87	0	1.39	198000	367000
BEASPONG-1	60	2003	0.87	0	1.39	84000	226000
BEASPONG-2	60	2003	0.87	0	1.39	84000	226000
BEASPONG-3	60	2003	0.87	0	1.39	84000	226000
BEASPONG-4	60	2003	0.87	0	1.39	84000	226000
BEASPONG-5	60	2003	0.87	0	1.39	84000	226000
BEASPONG-6	60	2003	0.87	0	1.39	84000	226000

BHAKRA(LB)-1	108	2003	0.87	0	1.39	156000	346000
BHAKRA(LB)-2	108	2003	0.87	0	1.39	156000	346000
BHAKRA(LB)-3	108	2003	0.87	0	1.39	156000	346000
BHAKRA(LB)-4	108	2003	0.87	0	1.39	156000	347000
BHAKRA(LB)-5	108	2003	0.87	0	1.39	156000	347000
BHAKRA(RB)-1	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-2	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-3	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-4	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-5	142	2003	0.87	0	1.39	205000	455000
GANGUWAL-1	29	2003	0.87	0	1.39	43000	150000
GANGUWAL-2	25	2003	0.87	0	1.39	43000	150000
GANGUWAL-3	24	2003	0.87	0	1.39	43000	150000
KOTLA-1	29	2003	0.87	0	1.39	43000	150000
KOTLA-2	25	2003	0.87	0	1.39	43000	150000
KOTLA-3	24	2003	0.87	0	1.39	43000	150000
MUKERIAN-1	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-2	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-3	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-4	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-5	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-6	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-7	20	2003	0.87	0	1.39	36000	93000
MUKERIAN-8	19	2003	0.87	0	1.39	36000	93000
MUKERIAN-9	20	2003	0.87	0	1.39	36000	93000
MUKERIAN-10	19	2003	0.87	0	1.39	36000	93000
MUKERIAN-11	20	2003	0.87	0	1.39	36000	93000
MUKERIAN-12	19	2003	0.87	0	1.39	36000	93000
SHANAN-1	15	2003	0.87	0	1.39	35000	60000
SHANAN-2	15	2003	0.87	0	1.39	35000	60000
SHANAN-3	15	2003	0.87	0	1.39	36000	60000
SHANAN-4	15	2003	0.87	0	1.39	36000	60000
SHANAN-5	50	2003	0.87	0	1.39	70000	120000
UBDC-1	15	2003	0.87	0	1.39	22000	21000
UBDC-2	15	2003	0.87	0	1.39	22000	21000
UBDC-3	15	2003	0.87	0	1.39	22000	21000
UBDC-4	15	2003	0.87	0	1.39	22000	21000
UBDC-5	15	2003	0.87	0	1.39	22000	21000
UBDC-6	15	2003	0.87	0	1.39	22000	22000
ANOOPGARH	9	2003	0.87	0	1.39	0	4000
JAWAHARSAGAR	99	2003	0.87	0	1.39	82000	348000
MAHI-1	25	2003	0.87	0	1.39	13000	55000
MAHI-2	25	2003	0.87	0	1.39	13000	57000
MAHI-3	45	2003	0.87	0	1.39	22000	95000
MAHI-4	45	2003	0.87	0	1.39	22000	95000
R.P.SAGAR	172	2003	0.87	0	1.39	91000	513000
RAJ-SMALL	14	2003	0.87	0	1.39	0	9000
CHIBRO-1	60	2003	0.87	0	1.39	87000	147000
CHIBRO-2	60	2003	0.87	0	1.39	87000	147000
CHIBRO-3	60	2003	0.87	0	1.39	87000	147000
CHIBRO-4	60	2003	0.87	0	1.39	87000	147000
DHAKRANI-1	11	2003	0.87	0	1.39	16000	37000
DHAKRANI-2	11	2003	0.87	0	1.39	16000	37000
DHAKRANI-3	12	2003	0.87	0	1.39	16000	37000
DHALIPUR-1	17	2003	0.87	0	1.39	27000	63000
DHALIPUR-2	17	2003	0.87	0	1.39	27000	63000
DHALIPUR-3	17	2003	0.87	0	1.39	27000	64000
KHARA-1	24	2003	0.87	0	1.39	41000	91000
KHARA-2	24	2003	0.87	0	1.39	41000	91000
KHARA-3	24	2003	0.87	0	1.39	41000	91000
KHATIMAGANGA	41.4	2003	0.87	0	1.39	59000	139000
KHODRI-1	30	2003	0.87	0	1.39	38000	71000
KHODRI-2	30	2003	0.87	0	1.39	38000	71000
KHODRI-3	30	2003	0.87	0	1.39	39000	71000
KHODRI-4	30	2003	0.87	0	1.39	39000	71000
KULHALST-IV-1	10	2003	0.87	0	1.39	16000	37000

KULHALST-IV-2	10	2003	0.87	0	1.39	16000	37000
KULHALST-IV-3	10	2003	0.87	0	1.39	16000	37000
CHILLA-1	36	2003	0.87	0	1.39	52000	120000
CHILLA-2	36	2003	0.87	0	1.39	52000	120000
CHILLA-3	36	2003	0.87	0	1.39	52000	121000
CHILLA-4	36	2003	0.87	0	1.39	52000	121000
MANERIBHALI-I1	30	2003	0.87	0	1.39	19000	99000
MANERIBHALI-I2	30	2003	0.87	0	1.39	19000	99000
MANERIBHALI-I3	30	2003	0.87	0	1.39	19000	99000
MATATILA-1	10	2003	0.87	0	1.39	16000	27000
MATATILA-2	10	2003	0.87	0	1.39	16000	27000
MATATILA-3	10	2003	0.87	0	1.39	17000	27000
OBRA-1-H	33	2003	0.87	0	1.39	26000	100000
OBRA-2-H	33	2003	0.87	0	1.39	26000	100000
OBRA-3-H	33	2003	0.87	0	1.39	26000	100000
RAMGANGA-1	66	2003	0.87	0	1.39	0	98000
RAMGANGA-2	66	2003	0.87	0	1.39	0	98000
RAMGANGA-3	66	2003	0.87	0	1.39	0	99000
RIHAND-1	50	2003	0.87	0	1.39	34000	138000
RIHAND-2	50	2003	0.87	0	1.39	34000	138000
RIHAND-3	50	2003	0.87	0	1.39	34000	137000
RIHAND-4	50	2003	0.87	0	1.39	34000	137000
RIHAND-5	50	2003	0.87	0	1.39	34000	137000
RIHAND-6	50	2003	0.87	0	1.39	34000	137000
TANAKPUR-1	30	2003	0.87	0	1.39	41000	69000
TANAKPUR-2	30	2003	0.87	0	1.39	41000	69000
TANAKPUR-3	30	2003	0.87	0	1.39	41000	69000
GANGACANAL	45.2	2003	0.87	0	1.39	32000	118000
SOBLA	6	2003	0.87	0	1.39	0	53000
TANAKPUR-4	30	2003	0.87	0	1.39	41000	70000
DADUPUR	6	2003	0.87	0	1.39	5000	13000
W.Y.C.-II	16	2003	0.87	0	1.39	16000	48000
BASPAII-1	100	2003	0.87	0	1.39	161000	241000
BASPAII-2	100	2003	0.87	0	1.39	161000	241000
BASPAII-3	100	2003	0.87	0	1.39	161000	241000
CHAMERA-II-1	100	2004	0.87	0	1.39	170000	254000
CHAMERA-II-2	100	2004	0.87	0	1.39	169000	254000
CHAMERA-II-3	100	2004	0.87	0	1.39	169000	254000
KOLDAM-1	200	2006	0.87	0	1.39	307000	461000
KOLDAM-2	200	2006	0.87	0	1.39	307000	461000
KOLDAM-3	200	2007	0.87	0	1.39	307000	461000
KOLDAM-4	200	2007	0.87	0	1.39	307000	461000
LARJI1-3	126	2004	0.87	0	1.39	131000	196000
GHANVI	22.5	2003	0.87	0	1.39	18000	26000
NATHPAJHAKRI-1&2	500	2003	0.87	0	1.39	663000	996000
NATHPAJHAKRI-3	250	2003	0.87	0	1.39	332000	497000
NATHPAJHAKRI-4	250	2003	0.87	0	1.39	332000	497000
NATHPAJHAKRI-5	250	2003	0.87	0	1.39	332000	497000
NATHPAJHAKRI-6	250	2003	0.87	0	1.39	332000	497000
PARVATI-II-1	200	2006	0.87	0	1.39	318000	476000
PARVATI-II-2	200	2006	0.87	0	1.39	318000	476000
PARVATI-II-3	200	2007	0.87	0	1.39	318000	476000
PARVATI-II-4	200	2007	0.87	0	1.39	318000	476000
CHENANI-II	7.5	2003	0.87	0	1.39	6000	12000
DULHASTI-1	130	2003	0.87	0	1.39	257000	386000
DULHASTI-2	130	2003	0.87	0	1.39	257000	386000
DULHASTI-3	130	2003	0.87	0	1.39	257000	386000
PAHALGAON	3	2003	0.87	0	1.39	2000	3000
PARNAIHEP1	12.5	2003	0.87	0	1.39	26000	54000
SEWA-III	9	2003	0.87	0	1.39	16000	31000
UPPERSINDH-II	70	2003	0.87	0	1.39	53000	109000
UPPERSINDH-III	35	2003	0.87	0	1.39	27000	54000
SHAHPURKHANDI	40	2004	0.87	0	1.39	51000	115000
SYLCANAL	50	2003	0.87	0	1.39	127000	190000
THEINDAM-1	150	2003	0.87	0	1.39	105000	235000
THEINDAM-2	150	2003	0.87	0	1.39	106000	235000

THEINDAM-3	150	2003	0.87	0	1.39	106000	235000
THEINDAM-4	150	2003	0.87	0	1.39	106000	235000
JAKHAM	5	2003	0.87	0	1.39	5000	22000
KATAPATHARHE	19	2006	0.87	0	1.39	19000	35000
DHAULIGANGA-I-1	140	2004	0.87	0	1.39	198000	369000
DHAULIGANGA-I-2	140	2004	0.87	0	1.39	198000	369000
KOTESHWAR-1	100	2005	0.87	0	1.39	108000	200000
KOTESHWAR-2	100	2005	0.87	0	1.39	108000	200000
KOTESHWAR-3	100	2006	0.87	0	1.39	108000	200000
KOTESHWAR-4	100	2006	0.87	0	1.39	108000	200000
LAKHWAR[VYASI]1	100	2005	0.87	0	1.39	55000	103000
LAKHWAR[VYASI]2	100	2005	0.87	0	1.39	55000	103000
MANERIBH-II-1	76	2004	0.87	0	1.39	82000	152000
MANERIBH-II-2	76	2004	0.87	0	1.39	82000	152000
MANERIBH-II-3	76	2004	0.87	0	1.39	82000	152000
MANERIBH-II-4	76	2004	0.87	0	1.39	82000	152000
RAJGHAT50%	22	2003	0.87	0	1.39	15000	29000
TEHRISTI-1	250	2003	0.87	0	1.39	251000	466000
TEHRISTI-2	250	2003	0.87	0	1.39	251000	466000
TEHRISTI-3	250	2003	0.87	0	1.39	251000	466000
TEHRISTI-4	250	2003	0.87	0	1.39	251000	466000
VISHNUPRAYAG-1	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-2	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-3	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-4	100	2003	0.87	0	1.39	118000	220000
VYASI[LAKWAR]	120	2004	0.87	0	1.39	132000	244000
LAKHWARVYASI3	100	2005	0.87	0	1.39	55000	103000
PARNAIHEP2	12.5	2004	0.87	0	1.39	26000	54000
PARNAIHEP3	12.5	2004	0.87	0	1.39	26000	54000
TEHRIII-1	250	2005	0.87	0	1.39	251000	465000
TEHRIII-2	250	2005	0.87	0	1.39	251000	465000
TEHRIII-3	250	2006	0.87	0	1.39	251000	465000
TEHRI-II-4	250	2006	0.87	0	1.39	251000	465000
SHAHPURKHANDI	40	2004	0.87	0	1.39	51000	114000
SHAHPURKHANDI	40	2004	0.87	0	1.39	51000	114000
SHAHPURKHANDI	40	2005	0.87	0	1.39	51000	114000
SHAHPURKHANDI	8	2004	0.87	0	1.39	10000	23000
MALANAHEP	86	2004	0.87	0	1.39	123000	185000

Appendix C

Candidate Plants

C-1: Candidate Thermal Plants

Name	*Coal 4 - 500*	*Coal 6 - 500*	*CCGT - 500*	*Nuclear - 500*
Fuel type used	Coal 4	Coal 6	Gas	Nuclear
Fuel consumption rate unit	000'kg/ MWh	000'kg/ MWh	000'm3/ MWh	000'gm/ MWh
Fuel consumption	0.7	0.7	0.2	0.027
Calorific value (kBtu/kg)	13.5	13.5	41.74	406350
CO2 emission factor (kg/MWh)	1026	1026	550	0
SO2 emission factor (kg/MWh)	6	6	0.4	0
NOx emission factor (kg/MWh)	2.5	2.5	1.64	0
Installed capacity (MW)	500	500	250	500
Earliest available year	2003	2003	2003	2006
Annual allowable maximum unit	60	30	80	6
Availability	0.71	0.71	0.8	0.58
Unit depreciable capital cost (k$)	450000	450000	175000	600000
Unit non-depreciable capital cost (k$)	50000	50000	19500	66000
Heat rate at full load (Mcal/MWh)	2500	2500	2062	2777
Operating cost (k$/MWh)	0.0012	0.0012	0.0008	0.0015
Annual maintenance hour	864	864	1296	896
Fixed O&M cost (k$/MWmonth	2	2	1.67	2.7

C-2: Candidate Hydro Plants

Name	*Capacity*	*Year*	*Unit*	*Cost*	*En. Sea.1*	*En. Sea.2*
Hibra	120	2007	2	143555	187200	280800
Palamaneri	100	2007	4	42265	137900	256100
Budhil	35	2008	2	37729	57200	85800
L. Nagpala	250	2008	2	82109	339325	630175
Kuther	130	2009	2	119444	188200	282300
Uhl st. III	50	2010	2	49019	80400	120600
Maner Bali	76	2010	4	84512	115850	215150
T. Vishnugadh	120	2010	3	56465	185033	343633
Parbati III	167	2010	3	106071	266266	399400
Dhauliganga II	70	2010	3	90683	111416	206916
Kishanganga	110	2011	3	100529	102500	239166
Kotlibhel	250	2012	4	72508	473462	879287
Uri II	70	2012	4	137877	108450	253050
Bursar	250	2014	4	144632	121950	284550
Shahpur Kandi	168	2014	1	299177	333440	708560
Sewa st II	60	2014	2	38258	47250	110250
Pakhal dul	250	2015	4	59941	44250	103250
Kishau	120	2015	5	153555	92890	172510
Parbati I	250	2015	3	278000	391200	586800

C-3: Existing Thermal IPPs

NAME	*Fuel type*	*Fuel con.*	*Cal. Value (kBtu/ kg)*	*CO2 emis. (kg/ MWh)*	*SO2 emis. (kg/ MWh)*	*NOx emis. (kg/ MWh)*	*Capacity (MW)*	*Heat rate (kcal/ kwh)*	*Oper. cost (000'$/ MWh)*	*Annual maint. (Hours)*	*Fixed O&M (000'$/ MWmonth)*
BARSINGSARLIG-1	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
BARSINGSARLIG-2	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
ROSAI/1	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
ROSAI/2	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
DHOLPURCCGT	GAS	0.237	41.74	540.95	0.39	1.65	233	2062	0.0008	1296	1.67
GLOBALBOARDCGT	GAS	0.237	41.74	540.95	0.39	1.65	126	2062	0.0008	1296	1.67
MAGNUMCCGT	GAS	0.237	41.74	540.95	0.39	1.65	24	2062	0.0008	1296	1.67
PHOENIXCCGT	GAS	0.237	41.74	540.95	0.39	1.65	170	2062	0.0008	1296	1.67

C-4: Existing Hydro IPPs

Name	*Capacity (MW)*	*EA year*	*Availibility*	*Opearting Cost (000'$/ MWh)*	*Fixed O&M cost (000'$/ MWmonth)*	*Energy - Season1 (MWh)*	*Energy-Season2 (MWh)*
BASPAII-1	100	2003	0.87	0	1.39	161000	241000
BASPAII-2	100	2003	0.87	0	1.39	161000	241000
BASPAII-3	100	2003	0.87	0	1.39	161000	241000
VISHNUPRAYAG-1	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-2	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-3	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-4	100	2003	0.87	0	1.39	118000	220000
MALANAHEP	86	2004	0.87	0	1.39	123000	185000

C-5: Candidate Thermal IPPs

Name	*Jawaharpur TPP*
Fuel type used	Coal 6
Fuel consumption rate unit	000'kg/MWh
Fuel consumption	0.7
Calorific value (kBtu/kg)	17.8
CO2 emission factor (kg/MWh)	1026
SO2 emission factor (kg/MWh)	6
NOx emission factor (kg/MWh)	2.5
Installed capacity (MW)	400
Earliest available year	2007
Annual allowable maximum unit	2
Availability	0.71
Unit depreciable capital cost (k$)	353391
Unit non-depreciable capital cost (k$)	39265
Heat rate at full load (Mcal/MWh)	2200
Operating cost (k$/MWh)	0.0012
Annual maintenance hour	864
Fixed O&M cost (k$/MWmonth)	2

C-6: Candidate Hydro IPPs

Name	*Capacity*	*Year*	*Unit*	*Cost*	*Season1*	*Season2*
Allan duhangan	96	2009	2	76955	136400	204600
K.Wangtoo	250	2007	4	286026	440200	660300
D. Sunda	35	2008	2	40250	56800	85200
Srinagar HEP	82.5	2007	4	95980	123000	185000

Appendix D

Candidate Plants

D-1: Candidate Thermal Plants

Name	*Coal 4 - 500*	*Coal 6 - 500*	*CCGT – 500*	*Nuclear - 500*	*PFBC - 450*	*IGCC - 400*	*BIGCC- 132*
Fuel type used	Coal 4	Coal 6	Gas	Nuclear	Coal 6	Coal 6	wood
Fuel consumption rate unit	000'kg/ MWh	000'kg/ MWh	000'm3/ MWh	000'gm/ MWh	000'kg/ MWh	000'kg/ MWh	000'kg/ MWh
Fuel Consumption	0.7	0.7	0.2	0.027	0.51	0.51	0.51
Calorific value (kBtu/kg)	13.5	13.5	41.74	406350	15.56	15.56	19.21
CO2 emission factor (kg/MWh)	1026	1026	550	0	907	551	71.64
SO2 emission factor (kg/MWh)	6	6	0.4	0	0.255	0.235	0.918
NOx emission factor (kg/MWh)	2.5	2.5	1.64	0	0.6	0.6	0.6
Installed capacity (MW)	500	500	250	500	450	400	132
Earliest available year	2004	2005	2003	2007	2005	2005	2005
Annual allowable Maximum unit	85	45	80	6	10	10	10
Availability	0.71	0.71	0.8	0.58	0.85	0.85	0.85
Unit depreciable Capital cost (k$)	450000	450000	175000	600000	510000	500000	162875
Unit non-depreciable Capital cost (k$)	50000	50000	19500	66000	52500	50000	18100
Heat rate at full load (Mcal/MWh)	2500	2500	2062	2777	2013	1850	2469
Operating cost (k$/MWh)	0.0012	0.0012	0.0008	0.0015	0.0012	0.0013	0.0174
Annual maintenance hour	864	864	1296	896	864	864	864
Fixed O&M cost (k$/MWmonth	2	2	1.67	2.7	2.2	2.32	5.4

D-2: Candidate Hydro Plants

Name	*Capacity*	*Year*	*Unit*	*Cost*	*Season1*	*Season2*
Hibra	120	2007	2	143555	187200	280800
K.Wangtoo	250	2007	4	286026	440200	660300
Palamaneri	100	2007	4	42265	137900	256100
Budhil	35	2008	2	37729	57200	85800
L. Nagpala	250	2008	2	82109	339325	630175
Kuther	130	2009	2	119444	188200	282300
Allan duhangan	96	2009	2	76955	136400	204600
Uhl st. III	50	2010	2	49019	80400	120600
Maner Bali	76	2010	4	84512	115850	215150
T. Vishnugadh	120	2010	3	56465	185033	343633
Parbati III	167	2010	3	106071	266266	399400
Dhauliganga II	70	2010	3	90683	111416	206916
Kishanganga	110	2011	3	100529	102500	239166
Kotlibhel	250	2012	4	72508	473462	879287
Uri II	70	2012	4	137877	108450	253050
Bursar	250	2014	4	144632	121950	284550
Shahpur Kandi	168	2014	1	299177	333440	708560
Sewa st II	60	2014	2	38258	47250	110250
Pakhal dul	250	2015	4	59941	44250	103250
Kishau	120	2015	5	153555	92890	172510
Parbati I	250	2015	3	278000	391200	586800

D-3: Existing DPG (Micro-hydro)

Name	Capacity (MW)	EA Year	Avail.	Opearting Cost (000'$/ MWh)	Fixed O&M cost (000'$/ MWmonth)	Generation pattern Season1	Generation pattern Season2
Karnah-I	1	2003	0.87	0	1.86	0.4166	0.3276
Karnah-II	1	2003	0.87	0	1.86	0.4166	0.3276
Stakna-I	2	2003	0.87	0	1.86	0.4166	0.3276
Stakna-II	2	2003	0.87	0	1.86	0.4166	0.3276
chennani-II-I	1	2003	0.87	0	1.86	0.4166	0.3276
chennani-II-II	1	2003	0.87	0	1.86	0.4166	0.3276
Sal st II-I	1	2003	0.87	0	1.86	0.5554	0.2808
Sal st II-II	1	2003	0.87	0	1.86	0.5554	0.2808
gumma-I	1.5	2003	0.87	0	1.86	0.5554	0.2808
gumma-II	1.5	2003	0.87	0	1.86	0.5554	0.2808
charanwala	1.2	2003	0.87	0	1.86	0.4166	0.3276
pugal 1	1.5	2003	0.87	0	1.86	0.4166	0.3276
RMC mangrol-I	2	2003	0.87	0	1.86	0.4166	0.3276
RMC mangrol-II	2	2003	0.87	0	1.86	0.4166	0.3276
RMC mangrol-III	2	2003	0.87	0	1.86	0.4166	0.3276
suratgarh-I	2	2003	0.87	0	1.86	0.4166	0.3276
suratgarh-II	2	2003	0.87	0	1.86	0.4166	0.3276
chitaura-I	1.5	2003	0.87	0	1.86	0.4860	0.3042
chitaura-II	1.5	2003	0.87	0	1.86	0.4860	0.3042
salwa-I	1.5	2003	0.87	0	1.86	0.4860	0.3042
salwa-II	1.5	2003	0.87	0	1.86	0.4860	0.3042
galogi-I	1	2003	0.87	0	1.86	0.4860	0.3042
galogi-II	1	2003	0.87	0	1.86	0.4860	0.3042
chirkilla	1	2003	0.87	0	1.86	0.4860	0.3042
urgam-I	1.5	2003	0.87	0	1.86	0.4860	0.3042
urgam-II	1.5	2003	0.87	0	1.86	0.4860	0.3042
nirgajni-I	2.5	2003	0.87	0	1.86	0.4860	0.3042
nirgajni-II	2.5	2003	0.87	0	1.86	0.4860	0.3042

D-4: Candidate DPG

Name	*Microhydro-2*	*Solar PV -2*	*Wind -2*
Fuel type used	Water	Solar	Wind
CO2 emission factor (kg/MWh)	0	0	0
SO2 emission factor (kg/MWh)	0	0	0
NOx emission factor (kg/MWh)	0	0	0
Installed capacity (MW)	2	2	2
Earliest available year	2003	2003	2003
Annual allowable Maximum unit	500	50	50
Availability	0.87	0.25	0.35
Unit depreciable Capital cost (k$)	2222.2	6000	1400
Unit non-depreciable Capital cost (k$)	0	0	0
Operating cost (k$/MWh)	0	0.0012	0.00075
Annual maintenance hour	0	168	240
Fixed O&M cost (k$/MWmonth	1.86	2.5	1.35

D-5: Daily energy generation pattern of micro-hydro plants

	1	2	3	4	5	6	7	8	9	10	11	12
Sea.1	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486
Sea.2	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486
	13	14	15	16	17	18	19	20	21	22	23	24
Sea.1	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.304
Sea.2	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.304

D-6: Daily energy generation pattern of wind plants

	1	2	3	4	5	6	7	8	9	10	11	12
Sea.1	0.3703	.3730	.3636	.3313	.3263	.2882	.2714	.2648	.2659	.3009	0.3636	0.409
Sea.2	0.3045	0.3080	0.3263	0.3414	0.3116	0.2511	0.2769	0.5344	0.7560	0.7824	0.8231	0.886
	13	14	15	16	17	18	19	20	21	22	23	24
Sea.1	0.5140	0.5344	0.5140	0.5006	0.4420	0.3275	0.2459	0.2358	0.2769	0.2986	0.3238	0.332
Sea.2	0.9160	0.9086	0.8940	0.9536	1.0000	0.7757	0.5768	0.4196	0.3376	0.3009	0.2974	0.311

D-7: Daily energy generation pattern of solar plants

	1	2	3	4	5	6	7	8	9	10	11	12
Sea.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0149	0.1293	0.3402	0.5544	0.7327	0.8539	0.924
Sea.2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0088	0.0859	0.3001	0.5557	0.7695	0.9234	1.000
	13	14	15	16	17	18	19	20	21	22	23	24
Sea.1	0.9271	0.8535	0.7258	0.5476	0.3326	0.1301	0.0169	0.0000	0.0000	0.0000	0.0000	0.000
Sea.2	0.9977	0.9176	0.7521	0.5341	0.2798	0.0786	0.0110	0.0000	0.0000	0.0000	0.0000	0.000

Appendix E

E-1: Technical data and cost characteristics of appliances in residential sector

Existing appliances to be replaced				*Efficient appliances considered*		
Type of appliance	*No. of appliances in year 2003 (Thousands)*	*Cost in US $*	*Life in years*	*Type of appliances*	*Cost in US $*	*Life in year*
40W GLS	15169.5	0.244	0.5	9W CFL	9.44	5
60W GLS	35395.5	0.244	0.5	11W CFL	9.66	5
100W GLS	45508.5	0.266	0.5	20W CFL	12.11	5

E-2: Technical data and cost characteristic of agricultural pumps

Number of agricultural pumps in 2003 (Thousand)	*Type of rectification*	*Saving in power (kW)*	*Life (years)*	*Cost ($)*
5075.044	Complete Rectification	1.5	20	333.34
	Partial Rectification	0.8	8	66.66

E-3: Penetration rates in percentage for considered DSM options

Year	*DSM 1*	*DSM 2*	*DSM 3*	*DSM 4*	*DSM 5*
2203	5	5	5	5	10
2004	6.3	6.3	6.3	6.3	12
2005	7.5	7.5	7.5	7.5	14
2006	8.8	8.8	8.8	8.8	16
2007	10	10	10	10	18
2008	12.5	12.5	12.5	12.5	22
2009	15	15	15	15	26
2010	17.5	17.5	17.5	17.5	30
2011	20	20	20	20	34
2012	22.5	22.5	22.5	22.5	38
2013	25	25	25	25	42
2014	26.3	26.3	26.3	26.3	44
2015	27.5	27.5	27.5	27.5	46
2016	28.8	28.8	28.8	28.8	48
2017	30	30	30	30	50

E-4: Normalized chronological load curve for considered DSM options

Block	*DSM 1 / DSM 2*		*DSM 3*		*DSM 4 / DSM 5*	
	Season 1	*Season 2*	*Season 1*	*Season 2*	*Season 1*	*Season 2*
1	0.027565	0.027731	0.006125	0.006162	0.275424	0.59322
2	0.027107	0.027277	0.006024	0.006061	0.275424	0.59322
3	0.026409	0.026985	0.005869	0.005997	0.275424	0.625
4	0.0267	0.027888	0.005933	0.006197	0.275424	0.741525
5	0.018813	0.020553	0.043897	0.047956	0.305085	0.987288
6	0.018505	0.021273	0.043178	0.049636	0.349576	1
7	0.01821	0.020761	0.04249	0.048442	0.349576	0.987288
8	0.018126	0.020918	0.042294	0.048809	0.349576	0.944915
9	0	0	0.022552	0.025345	0.275424	0.894068
10	0	0	0.022479	0.024126	0.275424	0.830508
11	0	0	0.022613	0.023573	0.275424	0.826271
12	0	0	0.02275	0.02386	0.275424	0.809322
13	0	0	0.023163	0.024017	0.305085	0.529661
14	0.8313	0.9394	0.8313	0.9394	0.305085	0.097458
15	0.9674	1	0.9674	1	0.038136	0.101695
16	1	0.9927	1	0.9927	0.038136	0.101695
17	0.9923	0.9864	0.9923	0.9864	0.038136	0.173729
18	0.9553	0.9642	0.9553	0.9642	0.245763	0.608051
19	0.8964	0.9113	0.8964	0.9113	0.245763	0.601695
20	0.027885	0.028317	0.006197	0.006293	0.245763	0.59322